supporting documentation shall be provided to SPP and include all fault and sequence of events data relevant to the cause of the misoperation.

The facility owner shall maintain the documentation of all operations for a minimum of one (1) year. The facility owner's processes should include items such as:

1) Uniform format to the extent possible.
2) Content guidelines
3) Requirements for periodic review.
4) Requirements for updating data.
5) Procedures for analysis of all trip misoperations.

7.2.5 Transmission Protection System Maintenance And Testing Programs

Facility owners shall have a protection system maintenance and testing program in place The facility owner shall demonstrate full compliance to the program for protection system maintenance and testing and that all required activities have been completed on schedule. The program shall be maintained and documented. The facility owner will be responsible for maintaining and providing required data for each facility. Each facility owner will provide updates to SPP or NERC within 30 days of a request. Each facility owner shall periodically test the protection system components and system on a frequency as needed to assure that the system is functional and correct. Protection System component maintenance and testing shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. For newer TPS with self-monitoring, having SCADA reporting for a TPS failure, and with successful downloading or viewing of data following operations, then such activity and application shall satisfy the testing and maintenance procedure requirements. The facility owner shall maintain the documentation of all maintenance and tests records for one test period. Protection systems and their associated maintenance and testing procedures should be designed to minimize the likelihood of personnel error, such as incorrect operation or inadvertent disabling. Protection and control systems shall be functionally tested when initially placed in service, when modifications are made, and at a frequency of no less than five (5) years to verify the dependability and security aspects of the design. The maintenance and testing program of the protection system should include provisions for relay calibration, functional trip testing, communications system testing, and breaker trip testing. All maintenance and testing shall be documented as described below:

1) Transmission protection system identification.
2) Summary of testing procedures.
3) Frequency of testing.
4) Date last tested.
5) Results of last testing.

7.2.6 Requests for Transmission Protection Systems Data

SPP shall function as a requesting agent and clearinghouse for the collection of TPS data on an as-needed basis. Facility owners should provide the requested data within thirty (30) days with a copy of the requested information forwarded to the SPP. If a facility owner cannot provide the requested data within this specified time frame, SPP shall be notified of the delay and the anticipated date of forwarding the requested data. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.2.7 Transmission Protection Systems Criteria Updates

The SPCWG will update, if necessary, this Transmission Protection Systems Criteria every three (3) years.

7.3 UNDER-FREQUENCY LOAD SHEDDING AND RESTORATION

7.3.1 Automatic Load Shedding

A major disturbance among the interconnected bulk electric system may result in certain areas becoming isolated and experiencing abnormally low frequency and voltage levels. The areas of separation are unpredictable. To provide load relief and minimize the probability of network collapse the following practices are established.

7.3.1.1 Operating Reserve

All SPP operating reserve shall be utilized before resorting to shedding firm load. During a period of declining frequency, there may be violent swings of both real and reactive power. For this reason, all generator governors and voltage regulators shall be kept in automatic service as much as practical.

7.3.1.2 Operating Principles

a. To realize the maximum benefit from a load shedding program the points at which the load is shed in a company area shall be widely dispersed. This can be accomplished at the sub-transmission and distribution voltage level where the types of load and the increments of load to be shed can be selected.

b. The time interval involved in shedding load is of extreme importance. System operators cannot and shall not be required to manually shed load during a period of rapidly declining frequency. The only practical way to remove load from a member in an attempt to stabilize the frequency is to do so automatically by the use of under-frequency relays. Since a geographical area or the timing of a period of low frequency cannot be predicted, all of the designated under-frequency relays on a member system shall be in service at all times. Under-frequency relays shall not be installed on transmission interconnections unless considered necessary and has been mutually agreed upon between the members involved.

c. The accepted practice of the electric industry is to shed load in a minimum of three steps. Should the frequency continue to decline after these three steps of load shedding, additional action may be required to protect generating machinery from mechanical damage. The actions may include opening of tie-lines, removal of generating units from the bus, additional steps of load shedding, or "island" operation may be utilized automatically with enough load left on a machine or plant to keep it in operation. A member can elect to use any one or a combination of these actions. It is recommended that this operation be performed at 58.5 Hz. Whatever is done by any one member shall be coordinated with neighboring members. A map or chart which shows additional actions that will be taken below a frequency of 58.7Hz shall be furnished to SPP.

7.3.1.3 Implementation

a Should the utilization of spinning reserve fail to stop a frequency decline, load shedding shall be initiated in steps as indicated below. The goal of the program is to prevent a cascading outage due to a frequency excursion and restore the system to a stable condition. Members must be ready to shed, in three steps, an accumulated minimum of thirty (30) percent of a member's current load. Current load shall be deemed as the one-minute average of the member's load prior to the first under-frequency relay action taken at 59.3 Hz. If system frequency decay is permanently stabilized to 60 Hz after UFLS implementation of Step 1 or Step 2 of the three steps of under-frequency load shedding (UFLS), it is not required to continue with the additional UFLS step(s).

This requirement shall be achieved as follows.

a. A member may dynamically arm and disarm UFLS relays to achieve the required load shedding totals, indicated in the chart below, by utilizing a load following program. For the purposes of this section, the term 'dynamically' means that no operator intervention is required to arm or disarm a UFLS relay, **or**
b. A member that does not dynamically arm and disarm UFLS relays shall install, or have installed on its behalf, UFLS relays with a total capability of shedding an accumulated minimum of thirty (30) percent of the member's current load up to a maximum of forty-five (45) percent. The relays shall be set to shed the accumulated minimum of thirty (30) percent total up to a maximum of forty-five (45) percent as indicated in the chart below Ideally, members would shed load in three increments of 10% each; however, due to varying load profiles, it is acceptable to shed increments of load as indicated in the chart below. At Step 1 the member is required to shed at least 10% of their current load but no more than 15%. At Step 2 the member is required to shed at least 20% of their current load but no more than 25%, and Step 1 load shedding may be considered an integral portion of Step 2. At Step 3 the member is required to shed at least 30% of their current load but no more than 45%, and Step 1 and Step 2 load shedding may be considered an integral portion of Step 3. For UFLS tripping of loads greater than 15% at Step 1, 25% at Step 2 and 45% at Step 3, a waiver must be acquired from SPP and any applicable SPP working group. Once installed, these UFLS relays shall remain in service to trip loads except for periods of testing and maintenance.

Regardless of the technique utilized only the non-intentional delays including operating times of relays and breakers, plus any intentional delay as allowed in

Criteria 7.3, shall delay the interruption of pre-event load for all events at the time of each event.

The ideal load shedding progression for a 1000 MW load would be:

Step	Frequency (Hz)	Accumulated Load Relief	Total load dropped (MW)
1	59.3	10% of 1000	100
2	59.0	20% of 1000	200
3	58.7	30% of 1000	300

This should be followed as far as practical.

Step	Frequency (Hz)	Minimum Accumulated Load Relief (%)	Maximum Accumulated Load Relief (%)
1	59.3	10	15
2	59.0	20	25
3	58.7	30	45

The following example is an acceptable progression of load shedding and meets SPP Criteria:

One minute average load prior to first load shedding step is 1000MW

Step	Frequency (Hz)	Load Shed (MW)	Load Shed this Step (%)	Total Load Shed (MW)	Accumulated % Total Load Shed
1	59.3	120	12	120	12
2	59.0	90	9	210	21
3	58.7	90	9	300	30

The following example is not an acceptable progression of load shedding by failing to meet SPP load shedding criteria to shed a minimum accumulation of 20% of the total load at Step 2:

One minute average load prior to first load shedding step is 1000MW

Step	Frequency (Hz)	Load Shed (MW)	Load Shed this Step (%)	Total Load Shed (MW)	Accumulated % Total Load Shed
1	59.3	120	12	120	12
2	59 0	70	7	190	19

Does not meet minimum criteria of 20%

3	58.7	110	11	300	30

The following example is not an acceptable progression of load shedding by failing to meet SPP load shedding criteria by exceeding the maximum accumulated load shed of 15% at Step 1:

One minute average load prior to first load shedding step is 1000MW

Step	Frequency (Hz)	Load Shed (MW)	Load Shed this Step (%)	Total Load Shed (MW)	Accumulated % Total Load Shed
1	59.3	160	16	160	16
2	59.0	70	7	230	23
3	58.7	70	7	300	30

Exceeds maximum criteria of 15%

b. The relays used to accomplish load shedding shall be high speed with no external intentional time delay devices employed. An exception to this policy would be on circuits serving considerable motor load (such as oil field or irrigation pumping load) which would cause the under-frequency relays to incorrectly operate when the source voltage is removed momentarily due to a transmission line fault.

c. In special cases, some members may elect to shed more than the allowable maximum of the system load on any step, for example, if they have an adverse ratio of load responsibility to generating capability. This situation should not be general and shall be considered on the merits of specific cases. As stated in requirement 2 of 7.3.1.3.a, in such cases, a waiver should be acquired from SPP and any applicable SPP working group.

d. The tripping of any generating unit by under-frequency relays or any other protective device during low frequency conditions shall be so coordinated that these units will not be tripped before the three steps of load shedding have been utilized. Should this not be practical due to the operating characteristics of certain units, then these members shall protect the interconnected systems by shedding a block of load equal to the capability of the generating unit that will be tripped and at the frequency which will remove the unit from service. If the unit is jointly owned, each of the joint owners shall shed a block of load equal to their share of the unit.

e. The coordination among members becomes critical when actions beyond Step 3 are utilized; particularly, on those members which have established extra high voltage (EHV) terminals as part of their transmission system and/or with generators connected directly to the EHV system. Careful consideration shall be given when opening only one end of an EHV line section which is energized; the open-ended voltage could rise to damaging levels and reactive flow towards the closed-end could have intolerable effects. Further, if generation is connected to the affected portion of the EHV network, that generating capability would be removed from an area where it is sorely needed. Consideration shall be given to the coordination of under-frequency relaying of the EHV transmission to maintain generating units on line and if necessary, carry portions of a neighboring system load to do so. System operators shall be alert to the effects of unloading the EHV network and be prepared to remove portions of the network should the voltage rise to intolerable levels.

7.3.1.4 Required Location And Model Data Reporting For Under-frequency Load Shedding Equipment

The number, type and location of Under-frequency Load Shedding (UFLS) equipment will normally be the responsibility of the facility owners based on recommendations by the owners' or SPP's studies. Information about installations will be provided by the facility owners to the SPP in accordance with NERC Standards and maintained in databases by the SPP staff for a period of at least three (3) years. These modeling databases shall be monitored as necessary by the SPP System Protection and Control Working Group (SPCWG). The Model Development Working Group, Transmission Assessment Working Group and Operating Reliability Working Group will review the databases and recommend that equipment with adequate capabilities is installed at critical locations throughout the system as determined in power flow and dynamic stability studies. The specific data that is required in SPP's circuit analysis models shall be maintained and submitted to SPP by the facility owners or their designated representatives on an annual basis or as otherwise required. This data shall include, but not be limited to, location, breaker, trip frequencies, amount of load shed by trip frequency, relay and breaker operating times, and any intentional delay of breaker clearing. Also required will be any related generation protection, tie tripping schemes, islanding schemes, or any other schemes that are part of or impact the UFLS programs.

7.3.1.5 Requirements for Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means (i.e. self-testing microprocessor relays) to periodically check the functionality and availability of the UFLS equipment in service. These tests shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request.

7.3.1.6 Periodic Review of Under-frequency Load Shedding Equipment

SPP members shall maintain a list of substations where UFLS equipment is located for all areas including those designated as being critical by the Transmission Assessment and Operating Reliability Working Groups. The facility owner will be responsible for providing required data on forms developed by the System Protection & Control Working Group and supplied by SPP. Each facility owner will provide updates to the SPP as requested. The SPP staff will maintain and update the UFLS equipment database. The Transmission Assessment and Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.3 1 4. The SPCWG will update, if necessary, this UFLS Criteria every three (3) years.

7.3.1.7 Requests for Under-frequency Load Shedding Data

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility Owners should provide the requested data within five (5) business days with a copy of the requested information forwarded to the SPP. However, it is recognized that significant disturbances may result in a large amount of equipment operations at multiple locations and that some equipment operations must be manually retrieved from the UFLS equipment's locations. These factors may make it impractical to retrieve and properly prepare the records and documentation within five (5) business days. In these cases, SPP shall be notified of the delay and the anticipated date of forwarding the requested data. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.3.1.8 Restoration

After the frequency has stabilized the following procedure shall be followed.

- **a.** In the event the frequency stabilized below 60 Hz, system operators shall coordinate operations to utilize all available generating capacity to the maximum extent possible in order to restore the frequency to 60 Hz. Deficient systems shall continue to shed load until the frequency can be restored to normal.
- **b.** At 60 Hz the isolated areas shall be synchronized with the remainder of the interconnected systems. Synchronization between individual members shall be performed only upon direct orders of the system operators of both companies involved.
- **c.** System operators shall coordinate load restoration as generating capability, voltage levels and tie-line loadings allow.
- **d.** Any shed load shall be restored only upon direct orders of the system operator. Extreme care shall be exercised as to the rate at which load is restored to the system in order that limits of generation and transmission line loading are not exceeded. Insofar as possible, supervisory control shall be used to restore load; otherwise, manual restoration is preferable to insure positive control by the system operators.
- **e.** It is recommended that a restoration plan be furnished by each company for use by its system operators for implementation of a coordinated and successful recovery.

7.3.2 Requirements of a Regional Under-frequency Load Shedding Program

The SPP shall develop, coordinate, and document a Regional UFLS program

7.3.2.1 SPP's Coordination of Under-frequency Load Shedding Program

This program shall coordinate UFLS programs within the sub-regions, Region, and where appropriate, among Regions. It shall also coordinate the amount of load shedding necessary to arrest frequency decay, minimize loss of load, and permit timely system restoration. For an effective plan, SPP shall coordinate programs including generation protection and control, under-voltage load shedding, Regional load restoration, and transmission protection and control. Details to be included shall include those specified in 7 3.1.4. SPP shall periodically conduct and document a technical assessment of the effectiveness of the design and implementation of its UFLS program. The first technical assessment of the program shall be completed by SPP no later than June 1, 2001 These assessments shall be completed at least every five years thereafter or as required by significant changes in system conditions. The documented results of such assessments shall be provided to NERC on request.

7.3.2.2 Coordination of Under-frequency Load Shedding Programs And Analyses With SPP

The facility owners and operators of an UFLS program shall ensure that their programs are consistent with Regional UFLS program requirements including automatically shedding load in the amounts and at the locations, frequencies, rates and times consistent with those Regional requirements. When an under-frequency event occurs which is below the initializing set points of their UFLS programs, the owners or operators shall analyze and document the event. Documentation of the analysis shall be provided to SPP and NERC on request in the time frames established in 7.3.1.7.

7.3.3 Manual Load Shedding

A situation can arise when a control area must reduce load even though the frequency is normal. Since an automatic load shedding program will be of no avail in this case, manual load shedding procedures shall be utilized. One of the basic principles of interconnected operation is that a control area will match the area generation to area load at 60 Hz at all times. Should a generation deficiency develop for any reason, arrangements shall be made with adjacent control areas to cover the deficiency; but failing this, the affected control area shall reduce the area load until the available generation is sufficient to match it. In some cases a generation deficiency can be foreseen and will develop gradually; whereas, in other cases the deficiency will develop immediately with no forewarning. A gradually developing deficiency can probably be offset by using conservation procedures; whereas, an immediate deficiency will probably require customer service interruption. The importance of a load reduction plan cannot be overemphasized. A plan is offered here which can be modified to fit individual cases.

7.3.3.1 Conservation

a. Interruption of service to interruptible customers. Utilize to the extent that the situation requires.

b. Reduction of load in company facilities.

c. Reduction of distribution voltage level. Utilize to the extent possible and as the situation requires.

d. Load reduction by request to company employees and general public. The company employees and the general public shall be notified through news media to curtail the use of electricity

e. Load reduction by request to bulk power users. Concurrent with voltage reduction and asking employees and the general public to reduce load, bulk power users (municipals and cooperatives) will be asked to reduce load in their areas using the same methods

f. Load reduction by large use customers. Large use commercial and industrial customers will be requested to curtail electric power usage where such curtailment will not seriously disrupt customers' operations.

7.3.3.2 Service Interruption

Manual load interruption shall be implemented by a pre-determined plan, an example of which follows.

a. Each company operating subdivision shall select distribution circuits in approximately 5% increments in the order of their priority that will be taken out of service. The 5% increments will be labeled "A", "B", "C", "D", "E", and "F". The interruption and the restoration of these circuits will be under the control of the system operator. When the system operator determines that load must be reduced, he shall direct the subdivision operators to open all "A" circuits. This will reduce the system load 5%. If further load reduction is necessary, the system operator shall direct all "B" circuits to be opened which will result in an additional 5% reduction This shall continue through "C", "D", "E", and "F" until the generation deficiency is eliminated.

b. The objective of this plan is to have no circuits open more than two hours. If the duration of the system emergency exists in excess of two hours and only the "A" circuits have been opened, then at the end of two hours the "B" circuits shall be opened and the "A" circuits reclosed If a 10% reduction is necessary, "C" and "D" circuits shall be opened and "A" and "B" reclosed, after "A" and "B" have been open for two hours. Obviously, no circuits shall be open longer than is absolutely necessary. The "E" and "F" circuits shall be opened to avoid opening "A" and "B" circuits twice in one day.

c. When a generation deficiency develops, or begins to develop, the system operator shall alert all involved operating personnel to the effect that certain circuits may have to be interrupted. This action will reduce the time required to execute circuit interruption orders of the system operator. Some control areas in SPP have extensive supervisory control systems while others have little, if any, supervisory control. Obviously, any implementation plan shall make best use of available equipment

7.4 Special Protection Systems Equipment

A Special Protection Systems (SPS) or Remedial Action Scheme (RAS) is designed to detect abnormal system conditions and take automatic pre-planned, coordinated, corrective action (other than the isolation of faulted elements) to provide acceptable system performance. SPS actions include among others, changes in demand (e.g., load shedding), generation, or system configuration to maintain system stability, acceptable voltages, or acceptable facility loadings All reviews of facilities as included in Criteria 7.4 shall be for those used to monitor and control transmission facilities operated at 100kV or above.

The SPS design shall not create cascading transmission outages or system instability. One possible SPS may be the automatic and sequential dropping of load, generation, or adjacent high voltage (HV) lines, if a HV line trips. A SPS does not include (a) underfrequency load shedding or undervoltage load shedding as they are addressed under NERC Planning Standards III.D, Criteria 7.3, and III.E or (b) fault conditions that must be isolated or (c) out-of-step relaying. The SPS shall not require operator action, and all actions of the SPS are automatic. SPS shall be automatically armed without human intervention when appropriate. The status indication of any automatic or manual arming of SPS shall be provided as SCADA alarm inputs.

7.4.1 Operating Requirements and System Redundancy

Special Protection Systems shall include redundancy such that no single protection system component failure would prevent the interconnected transmission systems from meeting the system performance requirements of NERC I.A. Standards on Transmission Systems in Categories A, B or C of the associated Table I. Each facility owner shall develop a plan for reviewing the need for redundancy in its existing special protection systems and for implementing any required redundancy. Documentation of these reviews shall be provided to NERC, SPP, and those entities responsible for the reliability of the interconnected transmission systems, on request. Also, the misoperation, incorrect operation, or unintended operation of an SPS when considered by itself and not in combination with any other system contingency shall meet the system performance requirements as defined under Category C of Table I of the NERC I.A Standards on transmission systems.

7.4.2 Location And Data Reporting For Special Protection Systems Equipment

The number, type and location of SPS equipment will normally be the responsibility of the facility owners based on recommendations by the owners' and SPP's studies. Information about installations will be provided by the facility owners to the SPP in accordance with NERC Standards and maintained in databases by the SPP staff for a period of at least five (5) years. These databases shall be monitored as necessary by the SPP System Protection and Control Working Group (SPCWG). The Transmission Assessment Working Group and Operating Reliability Working Group will review the databases and recommend that equipment with adequate capabilities be installed at critical locations throughout the system as determined in power flow and dynamic stability studies. The specific data that is required in SPP's circuit analysis models shall be maintained and submitted to SPP by the facility owners or their designated representatives on an annual basis or as otherwise required. This data shall represent the designed functionality of the system. Documentation by facility owners for each SPS utilized shall include details on its design, its operation, its control, its functional testing, and coordination with other schemes that are part of or impact the SPS.

7.4.3 Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means to periodically check the functionality of the SPS equipment in service. Component testing and maintenance shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests and maintains on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for one testing period SPS shall be functionally tested when initially placed in service, when modifications are made, and at a frequency of no less than five (5) years to verify the dependability and security aspects of the design. Each facility owner will provide updates to the SPP or NERC upon request.

7.4.4 Periodic Review of Special Protection Systems Equipment

SPP members shall maintain a list of substations where SPS equipment is located for all areas including those designated as being critical by the Transmission Assessment and Operating Reliability Working Groups. The facility owner will be responsible for providing required data on forms developed by the SPCWG and supplied by SPP. Each facility owner will provide updates to the SPP as requested. The SPP staff will maintain and update the SPS equipment database The Transmission Assessment and Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.4 2. The SPCWG will update, if necessary, this SPS Criteria every three (3) years.

Based upon (a) a five year interval or other interval as required by electric system changes, or (b) if a new SPS, or (c) if a modified SPS, each facility owner will review and document their SPS for compliance with Regional planning criteria and guides, and the NERC Planning Standard I.A including the associated Table I. This review shall include system studies to evaluate the consequences of: 1) the proper operation of the SPS, 2) the failure of an SPS to operate due to a single component failure of the SPS, and 3) the misoperation, incorrect operation, or the unintended operation of an SPS when considered by itself without any other system contingency. These consequences shall not include cascading transmission outages or system instability. These studies shall include the date that they were performed, who performed them, the methodology of the study, the results of the study, and when the next study is anticipated.

7.4.5 Requests for Special Protection Systems Data.

SPP shall function as a requesting agent and clearing house for the collection of SPS data on an as-needed basis. Facility owners should provide the requested data within thirty (30) days with a copy of the requested information forwarded to the SPP. If a facility owner cannot provide the requested data within this specified time frame, SPP shall be notified of the delay and the anticipated date of forwarding the requested data. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.4.6 Submittals Of Special Protection Systems Misoperations.

All misoperations of a SPS shall be reported to the SPP within five (5) business days after receipt of the request, or as soon as possible thereafter. Any of the following events constitute a reportable SPS misoperation:

1) Failure to Operate – Any failure of a SPS to perform its intended function within the designated time when system conditions intended to trigger the SPS occur.
2) Failure to Arm – Any failure of a SPS to automatically arm itself for system conditions that are intended to result in the SPS being automatically armed.
3) Unnecessary Operation – Any failure of a SPS that occurs without the occurrence of the intended system trigger condition(s) including human error.
4) Unnecessary Arming – Any automatic arming of a SPS that occurs without the occurrence of the intended arming system condition(s)
5) Failure to Reset – Any failure of a SPS to automatically reset following a return of normal system conditions if that is the design intent.

Misoperations at lower voltages that cause an operation of a SPS, in systems 100kV or higher, shall be reported. A detailed analysis of the misoperation, its consequences, and the corrective actions taken to prevent a reoccurrence will be reported to the SPP within thirty (30) days. SPP shall be notified of any delay and the anticipated date of forwarding the required data. This analysis to be provided by the facility owner shall include, at a minimum, the description of facility as identified on a form, developed by the SPCWG and supplied by SPP, including a complete summary report of the misoperation, its consequences, corrective actions taken, and any other additional actions that may be required beyond the point in time when the analysis is completed to include when these actions will be completed. The analysis and corrective actions shall be reviewed by the SPCWG. If these reported corrective actions are deemed inadequate, then the corrective actions that SPP recommends shall be completed as soon as possible subject to equipment availability.

7.4.7 Submittals For New And Modified Special Protection Systems

The owner of the SPS shall notify SPP of its intent to construct a new or modify an existing SPS with sufficient lead time to allow for an orderly review by SPP's working groups and committees. This notification will include statements on whether misoperation or failure of the SPS would have local, inter-company, inter-area or interregional consequences, when the SPS is planned for service, how long it is expected to remain in service, what specific contingency(s) it is designed to operate for and whether the SPS will be designed according to all SPP operating requirements of the bulk transmission system and NERC Standards. For a new or modified SPS prior to construction of facilities, three (3) copies of all applicable studies supporting the design requirements of the SPS and three (3) copies of a complete set of electrical design specifications, drawings and operating plans shall be submitted to the SPP with this notification. The drawings shall include a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams. The documentation of the proposed system will include any special conditions or design restrictions that exist in the proposed system.

The System Protection And Control, Transmission Assessment and Operating Reliability Working Groups will assess the SPS's conformance with all SPP operating requirements of the bulk transmission system and NERC Standards. If necessary, the working groups will request that the facility owner conduct additional studies and provide additional details of design specifications, drawings and operating plans. The results of such compliance review shall be documented with all recommendations that are deemed appropriate by the SPP and forwarded to the requesting party normally within 120 days from the date of request. The recommendations of SPP shall be completely incorporated into the design of the SPS.

A presentation will be made to appropriate working groups when a facility owner deviates from any of the SPP operating requirements of the bulk transmission system and NERC Standards as well as when a member system is in doubt as to whether the design meets these requirements. The facility owner shall arrange for the technical presentation by advising SPP approximately four months prior to the presentation and by providing copies of the materials to be presented 30 days prior. The facility owner will advise appropriate working groups of the basic design of the proposed system and include a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams. The proposed system should be explained with due emphasis on any special conditions or design restrictions that exist in the proposed system. A presentation will also be made to appropriate working groups relating to new facilities or a modification to an existing facility when requested by either a member system or a working group.

7.5 UNDERVOLTAGE LOAD SHEDDING

One characteristic of electric systems that experience heavy loadings on transmission facilities with relatively limited reactive power control is the susceptibility to voltage instability. Such instability can cause tripping of generation and transmission facilities resulting in loss of customer demand as well as collapse of the bulk transmission system. A major disturbance among the interconnected bulk electric systems may result in certain areas becoming isolated and experiencing abnormally low frequency and voltage levels. Since voltage collapse can occur rapidly, operators may not have sufficient time to stabilize the systems. Therefore, a load-shedding scheme that is automatically activated as a result of undervoltage conditions in portions of a system can be an effective means to stabilize the interconnected systems and mitigate the effects of a voltage collapse.

7.5.1 Program Participants

Facility Owners who determine it beneficial to install undervoltage load shedding (UVLS) equipment may do so However, UVLS schemes must coordinate with all protection and underfrequency load shedding schemes for the reliable operation of facilities operated at 100kV and above. Also, members are not required to install such equipment unless deemed necessary by either SPP or NERC to ensure the reliability of bulk transmission systems.

7.5.2 Operating Reserve And Principles

All SPP operating reserve shall be utilized before resorting to shedding firm load. All generator governors and voltage regulators shall be kept in automatic service as much as practical so that generating units may be used to their maximum capability for supplying voltage support during disturbances.

- **a.** To realize the maximum benefit from a load shedding program, the points at which the load is shed in a company area should be widely dispersed. This can be accomplished at the sub-transmission and distribution voltage level where the types of load and the increments of load to be shed can be selected.
- **b.** The time interval involved in shedding load is of extreme importance. System

operators cannot and shall not be required to manually shed load during a period of rapidly declining voltage. One practical way to remove load from a member in an attempt to stabilize the voltage is to do so automatically by the use of undervoltage relays. All of the designated undervoltage relays on a member system shall be in service at all times. Undervoltage relays shall not be installed on transmission interconnections unless considered necessary and has been mutually agreed upon between the members involved.

c. Loads may be shed in multiple steps. Whatever actions are planned or implemented by one member, including actions other than load shedding, shall be coordinated with neighboring members and SPP. All UVLS programs shall coordinate with underfrequency load shedding requirements of other members and SPP to maintain the reliability of the bulk transmission system operated at 100kV and above.

d. Should the utilization of various assets, such as responsive voltage-supporting resources, generation, capacitors and static var systems, fail to stop a voltage decline, load shedding shall be initiated as determined by the member of which is conditional upon the regional requirements of SPP. The relays used to accomplish load shedding shall be high speed with the necessary external intentional time delay devices employed to eliminate nuisance trips during faults, reclosing delays, etc.

7.5.3 Location And Data Reporting

The determination of the number, type and location of UVLS equipment will normally be the responsibility of the facility owners based on recommendations by the owners' or SPP's studies. Facility owners shall provide information about these installations to the SPP in accordance with NERC Standards within five (5) business days upon receipt of the request This information will be maintained in databases by the SPP staff for a period of at least three (3) years The SPP System Protection and Control Working Group (SPCWG) shall monitor these databases as necessary. The Transmission Assessment Working Group and Operating Reliability Working Group will review the databases and recommend that equipment with adequate capabilities be installed at critical locations throughout the system as determined in power flow and dynamic stability studies.

The specific data that is required in SPP's circuit analysis models shall be maintained and submitted to SPP by the facility owners or their designated representatives on an annual basis or as otherwise required. This data shall include, but not be limited to, type of equipment, location, breaker, trip voltages, amount of load shed by trip voltage, relay and breaker operating times, and any intentional delay of breaker clearing. Also required will be any related generation protection, tie tripping schemes, islanding schemes, or any other schemes that are part of or impact the UVLS programs

7.5.4 Monitoring, Analysis And Notification Of Misoperations

Each facility owner shall have a process in place for the monitoring, notification, and analysis of all UVLS trip operations. Any of the following constitute a reportable UVLS misoperation:

1) Failure to trip – Any failure of UVLS equipment to initiate a trip to the appropriate terminal when a voltage level is less than or equal to a low-voltage set point.
2) Slow Trip – A correct operation of UVLS equipment for a low-voltage condition where the relay system initiates tripping slower than the system design intends.
3) Unnecessary Trip With Acceptable Voltage – Any relay initiated operation of a circuit breaker when the voltage is within acceptable limits.
4) Unnecessary Trip Within Period Of Time Delay – Any relay initiated operation of a circuit breaker before an intended time delay has expired.
5) Unnecessary Trip, Other– The unintentional operation of a UVLS scheme which causes a circuit breaker to trip when no low-voltage condition is present. This may be due to vibration, improper settings, load swing, faulty relay, or human error.

Misoperations at lower voltages that cause an outage of a transmission component, operated at 100kV or higher, shall be reported. Documentation of all misoperations shall be provided to SPP and NERC within thirty (30) business days of the request Each facility owner shall document that it has fully complied with its process for monitoring, notification, and analysis of all trip operations. It shall also provide consistent documentation of all trip misoperations, indicating the cause and those corrective actions that have been or will be taken. The facility owner will be responsible for providing documentation of misoperations on a form, developed by the SPCWG and supplied by SPP, with applicable attachments. These attachments shall include all voltage and sequence of events data relevant to the cause of the misoperation of which is the basis for the documentation.

The facility owner shall maintain the documentation of all operations for a minimum of one (1) year. The facility owner's processes should include items such as:

1) Uniform format to the extent possible.
2) Content guidelines.
3) Requirements for periodic review.
4) Requirements for updating data.
5) Procedures for analysis of all trip misoperations.

7.5.5 Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means (i.e. self-testing microprocessor relays) to periodically check the functionality and availability of the UVLS equipment in service. These tests shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request

7.5.6 Periodic Review of Undervoltage Load Shedding Equipment

SPP members shall maintain a list of substations where UVLS equipment is located for all areas including those designated as being critical by the Transmission Assessment and Operating Reliability Working Groups. The facility owner will be responsible for providing required data on forms developed by the System Protection & Control Working Group and supplied by SPP. Each facility owner will provide updates to the SPP as requested. The SPP staff will maintain and update the UVLS equipment database The Transmission Assessment and Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.5.3. The SPCWG will update, if necessary, this UVLS Criteria every three (3) years

7.5.7 Requests for Undervoltage Load Shedding Data

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility Owners shall provide program information including equipment data within five (5) business days upon receipt of a request with a copy of the requested information forwarded to the SPP. Facility owners shall also provide documentation, within thirty (30) business days upon receipt of a request, relating to 1) all misoperations within the requested time frame, 2) an implemented maintenance program, and 3) an applicable technical assessment. SPP shall provide program information including equipment data to NERC within thirty (30) business days upon receipt of a request SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP Such requests will be considered to be a request from SPP staff.

7.5.8 Coordination of Undervoltage Load Shedding Programs

The facility owners and operators of an UVLS program shall ensure that their programs are consistent with Regional UVLS program requirements including automatically shedding load in the amounts and at the locations, voltages, rates and times consistent with those Regional requirements. When an undervoltage event occurs which is below the initializing set points of their UVLS programs, the owners or operators shall analyze and document the event. Documentation of the analysis shall be provided to SPP and NERC on request in the time frames established in 7.5 7.

7.6 AUTOMATIC RESTORATION OF LOAD

Following a disturbance when the frequency and voltage have stabilized, properly coordinated and implemented programs for the automatic restoration of load can be useful to minimize the duration of interrupted electric service. However, the design of such plans must ensure that the automatic restoration of load does not impede the restoration of the interconnected bulk electric facilities operated at 100kV or higher. After the automatic shedding of load by either underfrequency or undervoltage relaying schemes has occurred, the interconnected bulk electric facilities must first be stabilized with regard to both nominal frequency and voltage within appropriate limits prior to arming an automatic restoration of load system. Also, sufficient spinning reserves must be available such that the recreation of an underfrequency or undervoltage condition does not occur when electric service is restored. Then automatic load restoration programs can be used to effectively expedite the restoration of electric service to accommodate customer demands.

7.6.1 Program Participants

Facility Owners who determine it beneficial to install equipment for the automatic restoration of load (ARL) may do so. However, ARL schemes must coordinate with all protection as well as underfrequency (UFLS) and undervoltage load shedding (UVLS) schemes for the reliable operation of facilities operated at 100kV and above while not overloading any of these facilities. Also, members who install such equipment shall meet all requirements of SPP and NERC to ensure that the reliability of bulk transmission systems is maintained.

7.6.2 Operating Reserve And Principles

Available spinning reserves within SPP and each control area must be sufficient to serve the load to be energized by ARL schemes before arming such schemes. To prevent the use of ARL schemes when insufficient spinning reserves are available, ARL schemes shall be armed by automatic generation control systems of which are operated by or are coordinated with the appropriate control area(s). All generator governors and excitation equipment including voltage regulators shall be kept in automatic service when ARL schemes are armed so that the spinning reserve of available generating units may be used to their maximum capability for supplying real and reactive power during restoration. Additional requirements for the application of programs involving the automatic restoration of load are listed below.

a Whatever actions are planned or implemented by one member involving the automatic restoration of load shall be coordinated with other members, SPP and other Regions. All ARL programs shall coordinate with underfrequency and undervoltage load shedding programs as well as ARL programs of other members to maintain the reliability of the bulk transmission system operated at 100kV and above.

b. An ARL system shall not be armed unless all pre-designated conditions are satisfied within the control area unless a designated island or sub-area is specified. Unless removed from service for testing and maintenance purposes, an ARL system shall be automatically armed and remain so only when 1) indication that an UFLS or UVLS scheme has operated, 2) the governor and excitation systems of available generation are in the automatic mode, 3) spinning reserves of available generation are greater than or equal to the real and reactive power requirements of the pre-event load to be restored, adjusted to the forecasted daily load curve and changes in diversity, plus incremental losses, 4) an adequate system frequency has been achieved, 5) voltages throughout the transmission system are within valid limits, 6) all intended transmission system interconnects are closed, and 7) all intended breakers including those used for islanding are closed. However, operators of an island or control area that has separated from the remainder of the bulk transmission system may arm an ARL system for this specific area if 1) a neighboring system(s) has not achieved or maintained an adequate frequency or voltage levels within acceptable limits, and 2) all of the conditions specified above are met except that all intended transmission system interconnects or islanding breakers may not be closed.

c. The time intervals involved in the automatic restoration of loads is of extreme importance. The restoration of too much load at one or over time relative to the capacity of available generating units given their dynamic characteristics may result in an unstable system. Therefore, loads to be automatically restored over time shall not exceed the ramping capabilities of the available generation. Also, upon being armed, ARL equipment shall restore load in multiple blocks by design to minimize the possibility of causing an underfrequency or undervoltage condition.

d. When any portion of the generation required to serve restored load is physically separated from the load by facilities within another control area, then adequate facilities between the generation and load with sufficient capacity to transfer the power shall be verified and applicable breakers shall be closed before the ARL system is armed.

e. Only those loads interrupted by UFLS and UVLS schemes may be restored by ARL equipment. Therefore, if either a UFLS or UVLS scheme did not interrupt a given load, then the use of ARL equipment shall not be used to restore the load. When UVLS equipment is used to trip loads, then the local voltage shall be within acceptable limits before the local ARL equipment energizes the load.

f. The points at which the load is restored in a company area should be widely dispersed This can be accomplished at the sub-transmission and distribution voltage level where the types of load and the increments of load to be restored can be selected.

g. Should the utilization of spinning reserve fail to adequately stabilize either frequency or voltage in a control area or designated portion thereof after restoring service to loads, or portions thereof, controlled by ARL equipment, the ARL equipment of said area shall be automatically disarmed. ARL schemes shall be designed and installed to restore load only once before being rearmed manually or by system operators via SCADA

7.6.3 Location And Data Reporting

The determination of the number, type and location of ARL equipment will normally be the responsibility of the facility owners based on recommendations by the owners' or SPP's studies. The technical assessments of ARL applications conducted by or on behalf of the facility owner shall validate the coordination with underfrequency and undervoltage programs within SPP and other Regions as necessary. Facility owners shall provide information about these installations to the SPP in accordance with NERC Standards within five (5) business days upon receipt of the request. This information will be maintained in databases by the SPP staff for a period of at least three (3) years. The SPP System Protection and Control Working Group (SPCWG) shall monitor these databases as necessary. The Transmission Assessment Working Group and Operating Reliability Working Group will review the databases as well as technical assessments conducted by facility owners and recommend that equipment with adequate capabilities be installed, or removed as necessary, at critical locations throughout the system as determined in power flow and dynamic stability studies.

The specific data that is required in SPP's circuit analysis models shall be maintained and submitted to SPP by the facility owners or their designated representatives on an annual basis or as otherwise required. This data shall include, but not be limited to, type of equipment, location, breaker, minimum voltage and frequency thresholds, amount of load shed that is to be restored, relay and breaker operating times, and any intentional delay of breaker closing. Also required will be any related generation protection, tie-closing schemes, islanding schemes, or any other schemes that are part of or impact the ARL programs.

7.6.4 Monitoring, Analysis And Notification Of Misoperations

Each facility owner shall have a process in place for the monitoring, notification, and analysis of all ARL closing operations. Any of the following constitute a reportable ARL misoperation.

1) Failure to close – Any failure of armed ARL equipment to initiate a close to the appropriate circuit breaker when a local voltage and/or frequency level is greater than or equal to applicable set points.
2) Slow Close – A correct operation of armed ARL equipment where the relay system initiates closing slower than the system design intends.

3) Unnecessary Close By Unarmed Equipment – Any initiated closing of a circuit breaker when all pre-designated conditions are not met.
4) Unnecessary Close, Other– The unintentional operation of an unarmed ARL scheme that causes a circuit breaker to close when no event had previously occurred. This may be due to vibration, improper settings, faulty relay, or human error.

Documentation of all misoperations shall be provided to SPP and NERC within thirty (30) business days of the request. Each facility owner shall document that it has fully complied with its process for monitoring, notification, and analysis of all trip operations. It shall also provide consistent documentation of all closing misoperations, indicating the cause and those corrective actions that have been or will be taken. The facility owner will be responsible for providing documentation of misoperations on a form, developed by the SPCWG and supplied by SPP, with applicable attachments. These attachments shall include all voltage, frequency and sequence of events data relevant to the cause of the misoperation of which is the basis for the documentation.

The facility owner shall maintain the documentation of all operations for a minimum of one (1) year. The facility owner's processes should include items such as:

1) Uniform format to the extent possible.
2) Content guidelines.
3) Requirements for periodic review.
4) Requirements for updating data.
5) Procedures for analysis of all closing misoperations.

7.6.5 Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means to periodically check the functionality and availability of the ARL equipment in service. These tests shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request.

ARL systems shall be functionally tested when initially placed in service, when modifications are made, and at a frequency of no less than three (3) years to verify the dependability and security aspects of the design. The maintenance and testing program of the ARL system should include provisions for relay calibration, functional trip testing, communications system testing, and breaker closure testing. All maintenance and testing shall be documented as described below:

1) Automatic Restoration of Load system identification.
2) Summary of testing procedures.
3) Frequency of testing.
4) Date last tested
5) Results of last testing.

7.6.6 Periodic Review of Equipment

SPP members shall maintain a list of substations where ARL equipment is located for all areas including those designated as being critical by the Transmission Assessment and Operating Reliability Working Groups. The facility owner will be responsible for providing required data on forms developed by the System Protection & Control Working Group and supplied by SPP. Each facility owner will provide updates to the SPP as requested The SPP staff will maintain and update the ARL equipment database. The Transmission Assessment and Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.6.3. The SPCWG will update, if necessary, this ARL Criteria every three (3) years.

7.6.7 Requests for Data

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility Owners shall provide program information including equipment data within five (5) business days upon receipt of a request with a copy of the requested information forwarded to the SPP. Facility owners shall also provide documentation, within thirty (30) business days upon receipt of a request, relating to 1) all misoperations within the requested time frame, 2) an implemented maintenance program, and 3) an applicable technical assessment. SPP shall provide program information including equipment data to NERC within five (5) business days upon receipt of a request. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.6.8 Coordination of Programs

The facility owners and operators of an ARL program shall ensure that their programs are consistent with Regional ARL program requirements including automatically restoring load in the amounts and at the locations, range of voltages and frequencies, rates and times consistent with those Regional requirements. When an undervoltage or underfrequency event occurs which initiates the utilization of ARL programs, the owners or operators shall analyze and document the event. Documentation of the analysis shall be provided to SPP and NERC on request in the time frames established in 7.6.7.

7.6.9 Submittals For New And Modified ARL Systems

The owner of the ARL system shall notify SPP of its intent to install a new or modify an existing ARL with sufficient lead time to allow for an orderly review by SPP's working groups and committees. This notification will include statements on whether misoperation or failure of the ARL system would have local, inter-company, inter-area or interregional consequences, when the ARL system is planned for service, how long it is expected to remain in service and whether the ARL system will be designed according to all SPP operating requirements of the bulk transmission system and NERC Standards. For a new or modified ARL system prior to installation of facilities, three (3) copies of all applicable studies supporting the design requirements of the ARL system and three (3) copies of a complete set of electrical design specifications, drawings and operating plans shall be submitted to the SPP with this notification. The drawings shall include a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams The documentation of the proposed system will include any special conditions or design restrictions that exist in the proposed system.

The System Protection And Control, Transmission Assessment and Operating Reliability Working Groups will assess the ARL system's conformance with all SPP operating requirements of the bulk transmission system and NERC Standards. If necessary, the working groups will request that the facility owner conduct additional studies and provide additional details of design specifications, drawings and operating plans. The results of such compliance review shall be documented with all recommendations that are deemed appropriate by the SPP and forwarded to the requesting party normally within 120 days from the date of request. The recommendations of SPP shall be completely incorporated into the design of the ARL.

A presentation will be made to appropriate working groups when a facility owner deviates from any of the SPP operating requirements of the bulk transmission system and NERC Standards as well as when a member system is in doubt as to whether the design meets these requirements. The facility owner shall arrange for the technical presentation by advising SPP approximately four months prior to the presentation and by providing copies of the materials to be presented 30 days prior. The facility owner will advise appropriate working groups of the basic design of the proposed system and include a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams. The proposed system should be explained with due emphasis on any special conditions or design restrictions that exist in the proposed system. A presentation will also be made to appropriate working groups relating to new facilities or a modification to an existing facility when requested by either a member system or a working group.

7.7 Generation Control and Protection

The objectives of protective relaying and control schemes within generation facilities are to promptly detect abnormal conditions and isolate or control equipment to minimize damage to equipment. Some of these abnormal conditions which will result in an alarm or tripping of generation include faults, overload, overheating, off-frequency, loss of field, motoring, single-phase or unbalance current operation, and out-of-step. The selection and settings of equipment should not result in erroneous tripping for acceptable operating conditions or for faults outside the intended zones of protection.

Generation Control and Protection Systems (GCP) must be coordinated with excitation and governor controls to minimize generator tripping during disturbance-caused abnormal voltage, current and frequency conditions. Therefore, protection and control schemes should be designed and installed with appropriate settings to provide a reasonable balance between the need for the generator to support the interconnected electric systems during abnormal conditions and the need to adequately protect the generator equipment from damage. All reviews, monitoring and analysis of each generator, rated at 20MW or above, shall be completed as described in Criteria 7.7.

7.7.1 Reviews Of Components And Systems

The owner shall conduct periodic reviews of the components and systems that make up the generation protection system to assure that components and systems function as desired to minimize outages. The design and implementation of all new protection schemes shall be in accordance with IEEE and ANSI Standards, Guides and Recommended Practices as well as NERC Standards and Guides. Should it be determined that the design and application of protection equipment do not adhere to such requirements, then these findings, as a result of this review, shall be documented including a plan for achieving the necessary results. These reviews are to be completed as system changes dictate, or more frequently as needed based on misoperations as identified in Criteria 7.7.2. The reviews should include, but not be limited to, the following items:

1) Review of relay settings.
2) Current carrying capability of all components (Bus, cables, lines, CTs, breakers, switches, etc.).
3) Interrupting capability of all components (breakers, fuses, etc.).
4) Breaker failure and trip schemes.

The design of protection systems, both in terms of circuitry and physical arrangement, should facilitate periodic testing and maintenance Generator protection systems should not operate for stable power swings except when that particular generator is out of step with the remainder of the system. Loss of excitation and out of step relays should be set with due regard to the performance of the excitation system.

All underfrequency, overfrequency, undervoltage and overvoltage protection systems shall be coordinated with system underfrequency and undervoltage load shedding schemes. Power plant auxiliary motors should not trip or stall for momentary undervoltage associated with the contingencies as defined in Categories A, B and C of NERC I.A Standards unless the loss of the associated generating unit(s) would not cause a violation of the contingency performance requirements.

Redundant generator protection schemes are required for all new generator installations and all re-powering projects where the generator is rated at 20MW or above. Redundant generator protection schemes for the step-up transformer and the main auxiliary transformer (if any) are not required but encouraged. Where redundant protection systems are being used, efforts should be made to use separate current transformers, potential transformers, and DC control power circuits to minimize the risk of both systems being disabled by a single event or condition.

The use of dual trip coils, if available, on both generator and unit circuit breakers are required for all new generator installations at 20MW or above. The installation of breaker failure relaying for generator and unit circuit breakers are also required for all new generator installations at 20MW or above. The addition of breaker failure relaying for all generator and unit circuit breakers at existing sites is not required but encouraged.

7.7.2 Monitoring, Analysis And Notification Of Misoperations

Each facility owner shall have a process in place for the monitoring, notification, and analysis of all generation protection trip operations. Any of the following constitute a reportable misoperation of generation protection equipment and schemes:

1) Failure to trip – Any failure of a GCP to initiate a trip when required.
2) Slow Trip – A correct operation of a GCP slower than the system design intends.
3) Unnecessary Trip– The unintentional operation of a GCP that causes a unit's output to be significantly reduced or causes the unit to trip when not required. This may be due to any number of factors such as equipment failure, incorrect settings, and relay misapplication.

Misoperations occuring prior to synchronization need not be reported, but shall be investigated and corrected to prevent possible misoperations when the unit is synchronized to the system. Documentation of all protection misoperations shall be provided to SPP and NERC within thirty (30) business days of the request.

Each facility owner shall document that it has fully complied with its process for monitoring, notification, and analysis of all GCP trip operations. It shall also provide consistent documentation of all GCP trip misoperations, indicating the cause and those corrective actions that have been or will be taken. The facility owner will be responsible for providing documentation of misoperations on a form supplied by SPP. When requested, supporting documentation shall be provided and include all fault, disturbance, load and sequence of events data relevant to the cause of the misoperation.

The facility owner shall maintain the documentation of all operations for a minimum of one (1) year. The facility owner's processes should include items such as:

1) Uniform documentation format to the extent possible.
2) Content guidelines.
3) Requirements for periodic review
4) Requirements for updating data.
5) Procedures for analysis of all trip misoperations.

7.7.3 Generation Protection System Maintenance And Testing Programs

Facility owners shall have a protection system maintenance and testing program in place. The facility owner shall demonstrate full compliance to the program for protection system maintenance and testing, demonstrating that all required activities have been completed on schedule. The program shall be maintained and documented. The facility owner will be responsible for maintaining and providing required data for each facility. Each facility owner will provide updates to SPP or NERC within 30 days of a request.

The facility owner shall maintain the documentation of all maintenance and tests records for one test period. Protection systems and their associated maintenance and testing procedures should be designed to minimize the likelihood of personnel error, such as incorrect operation or inadvertent disabling. Protection and control systems shall be functionally tested when initially placed in service, when modifications are made, and at a frequency of no less than five (5) years to verify the dependability and security aspects of the design.

Each facility owner shall periodically test the protection system components on a frequency as needed to assure that the system is functional and correct. The maintenance and testing of system components, i e. relays, shall be completed based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation but at least every three (3) years. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. For newer GCP Systems with self-monitoring, having SCADA reporting for a GCP failure, and with successful downloading or viewing of data following operations, then such activity and application shall satisfy the testing and maintenance procedure requirements.

The maintenance and testing program of the protection system should include provisions for relay calibration, functional trip testing, and breaker trip testing All maintenance and testing shall be documented as described below.

1) Generation protection system identification.
2) Summary of testing procedures.
3) Frequency of testing.
4) Date last tested
5) Results of last testing.

7.7.4 Requests for Data

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility Owners shall provide program information including equipment data within five (5) business days upon receipt of a request with a copy of the requested information forwarded to the SPP. Facility owners shall also provide documentation, within thirty (30) business days upon receipt of a request, relating to 1) all misoperations within the requested time frame, and 2) an implemented maintenance and testing program SPP shall provide program information including equipment data to NERC within five (5) business days upon receipt of a request. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.7.5 Coordination of Programs

The facility owners and operators of a GCP program shall ensure that their programs are consistent with Regional GCP program requirements effective January 1, 2002. When a disturbance, fault, or misoperation occurs which initiates the utilization of GCP equipment and schemes, the owners or operators shall analyze and document the event. Documentation of all misoperations shall be provided to SPP and NERC on request in the time frames established in 7.7.4. Generator owners/operators shall have a generator protection system maintenance and testing program in place.

7.7.6 Generation Protection Systems Criteria Updates

The SPCWG will update, if necessary, this Generation Control and Protection Systems Criteria every three (3) years.

7.8 Generator Controls – Status and Operation

7.8.1 Generator Excitation System Control Operation

All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation systems in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless approved by the control area operator

7.8.1.1 Reporting Procedures

Control Area Operators shall implement procedures that require Synchronous Generator Operator/Owners to provide information to the Control Area Operator, SPP, and NERC upon request (30 business days) concerning the generators' automatic voltage control regulator. The procedures shall include the following.

a. Summary report showing the number of hours each synchronous generator did not operate in automatic voltage control mode during each calendar month. Information shall be provided on the "Generator Owner/Operator Excitation System Summary Report" supplied by SPP, if control area operator does not have its own form.
b. Detailed reports of the date, duration, and reason for each instance in which a synchronous generator was not operated in the automatic voltage control mode for a specific calendar month. Information shall be provided on the "Generator Unit Excitation System Status Report" supplied by SPP, if control area operator does not have its own form.
c. The Generator Owner/Operator shall retain the reports mentioned in (a.) and (b.) for a period of 12 rolling months.

7.8.1.2 Exempt Generators

Control Area operators shall have criteria stating which generators may be exempt from these procedures. Exemptions shall include the following.

a. Generator output less than 20MW
b Other criteria as control area operator deems appropriate.

7.8.2 Generator Operation for maintaining Network Voltage

Synchronous generators shall maintain a network voltage or reactive power output as required by the control area operator within the reactive capability of the units.

7.8.2.1 Control Area Responsibilities

a. Each control area operator shall specify a voltage or reactive schedule to be maintained by each synchronous generator at a specified bus and shall provide this information to the generator owner/operator. Documentation of the information shall be provided on the "Generator Owner/Operator Voltage Schedule Requirements" report supplied by SPP, if the control area operator does not have its own form This information shall be made available to SPP and NERC on request (30 business days)
b Each control area operator shall maintain a list of synchronous generators that are exempt from the requirement of maintaining a network voltage or reactive schedule The list of exempt generators shall be made available to SPP and NERC on request (30 business days) and shall be supplied on "Control Area Operator's List of Exempt Generators" report supplied by SPP, if control area does not have its own form.

7.8.2.2 Generator Owner/Operator Responsibility

a. Synchronous generator owner/operators shall maintain the voltage or reactive output as specified by the control area operator
b. When requested by SPP and NERC, the synchronous generator owner/operator shall provide (30 business days) a log that specifies the date duration, and reason for not maintaining the established voltage or reactive schedule, along with approvals for such operation received from the transmission operator. This information shall be provided on the "Generator Unit Voltage Schedule Status Report" supplied by SPP, if control area operator does not have its own form.

7.8.3 Generator Step-Up and Auxiliary Transformer Tap Settings

Generator step-up and auxiliary transformers shall have their tap settings coordinated with electric system voltage requirements.

7.8.3.1 Reporting Procedures

Control Area operators shall implement procedures concerning the reporting and changing of transformer tap settings. The procedures shall at a minimum include the following.

a. Owner/Operators shall provide current tap settings, tap setting ranges, and impedence data for all Generator Step-Up (GSU) and Auxiliary Transformers to the control area operator, SPP, and NERC upon request (30 business days). This information shall be supplied on 'Generator Unit Transformer Tap Setting Report" supplied by SPP is control area operator does not have its own form.
b When tap setting changes are necessary, the control area operator shall notify generator owner/operator with "Generator Unit Transformer Tap Setting Change Request" supplied by SPP, if control area operator does not have its own report. In this report, tap setting changes are specified along with a technical justification for the changes.
c. Generator Owner/Operators shall have a period of nine (9) months in which tap setting changes must be made. After setting changes have been made, Generator Owner/Operator shall supply new "Generator Unit Transformer Tap Setting Report" for the affected generating station.
d. Criteria for Generating units whose GSU and AUX transformers would be exempted.
e List of generating units that meet exemption criteria shall be documented on "Generation Units Exempt from Tap Setting Reporting Procedures" report supplied by SPP, if Control Area Operator does not have its own form.

7.8.4 Generator Performance during Temporary Excursions

7.8.4.1 Excursions in Frequency and Voltage

Generators shall be able to sustain temporary excursions in underfrequency, overfrequency, undervoltage, and overvoltage conditions. The protective relay systems regarding these conditions shall be coordinated with SPP system underfrequency and undervoltage load shedding schemes.

SPP's underfrequency load shedding plan allows for three stages of load shed at frequencies of 59.3, 59.0, and 58 7 Hz. The members shall shed 10% of their load at each stage in an effort to stop the decline in frequency. Control Areas may elect to implement a fourth stage at 58.5 Hz which can call for the opening of tie-lines, removal of generating units from buses, additional steps of load shedding, or the breakup of the transmission system into predetermined islands with balanced amounts of generation and load in each island. Due to the structure of the underfrequency load shedding plan, it is necessary that generators be able to sustain frequencies to at least 58 5 Hz so that the load shedding plan works as designed. Any generator that must trip off line prior to system frequency declining to 58.5 Hz must have a block of load equal to the generator's output capability tripped at the same frequency as the generating unit.

In the absence of a regional or control area undervoltage load shedding plan, generators shall be able to sustain non-interruptible operation at voltages between 92% and 105% of the nominal transmission voltage at the generator bus During Emergency and/or transient system conditions, all reasonable measures should be taken to avoid tripping of the generator due to high or low voltage.

7.8.4.2 Excursions in Real and Reactive Power Output

Generators shall be able to sustain temporary excursions in real and reactive power output that may occur during a period of declining frequency or voltage. For this reason, all generator governors and automatic voltage regulators shall be kept in automatic mode as much as practical. A generator shall not trip during stable power swings except when that particular generator is out of step with the remainder of the system.

Generators shall be able to run at maximum rated reactive and real output according to each unit's Capability Curves during emergency conditions for as long as acceptable frequency and voltages allow the generator to continue to operate.

7.8.4.3 Exempt Generators

Generators shall be exempt from this section if they meet the following criteria:

Generator output less than 20MW

7.8.5 Generator Voltage Regulator Controls and Limit Functions

Voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) shall coordinate with the generator's short term duration capabilities and protective relays.

7.8.5.1 Reporting Procedures

Generator Owner/Operators shall provide control area, SPP, and NERC as requested (30 business days) with information that ensures generator controls coordinate with the generator short term duration capabilities and protective relays. The information shall be supplied on the "Voltage Regulator Control Setting Status Report" as supplied by SPP is control area operator does not have its own form

7.8.6 Governor Control Operation

Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency. Governors' speed regulation response shall be set such that a decrease in system frequency causes the governor to respond by increasing the generator real power output.

7.8.6.1 Reporting Procedures

a. Generator Owner/Operators shall provide control area, SPP, and NERC as requested (30 business days) with the characteristics of the generator's speed/load governing system. Boiler or nuclear reactor control shall be coordinated to maintain the capability of the generator to aid control of system frequency during an electric system disturbance. Information shall be supplied on "Generator Governor Characteristic Reporting" report supplied by SPP if control area operator does not have its own form.
b. Non-functioning or blocked speed/load governor controls shall be reported to control area, SPP, and NERC on request (30 business days). Information shall be supplied on "Non-Functioning Governor Control" report supplied by SPP if control area operator does not have its own form.

7.9 Inter-Connection Revenue Metering

7.9.1 Meter Technical and Data Reporting Protocols

The protection design may also include various types and accuracies of metering and associated equipment. The metering may include, but not be limited to, the following: local station or plant annunciated / displayed metering, SCADA type operational metering exchanged among parties within a station or plant, SCADA type station to control center metering used for operational purposes, control center to control center ICCP type metering, and inter-connection revenue metering. These metering types may or may not have specific SPP criteria requirements Other metering design requirements may need to be referenced when creating metering and protection design, especially those that include the control center to control center metering and revenue metering. SPP has specific functional and design type requirements for Inter-Connection Revenue Metering.

7.9.2 Revenue "Meter Technical and Data Reporting Protocols" Cross Reference

The Southwest Power Pool (SPP) Market Working Group's (MWG) Settlement Data and Meter Standards Task Force (SDMSTF) subcommittee has jurisdictional control over the power plant and transmission system "inter-connection settlement revenue metering". The SPP System Protection and Control Working Group (SPCWG) and other parties providing inter-connection settlement revenue metering designs in the SPP area must refer to the MWG - - SDMSTF Market Protocol Document "Appendix D: Meter Technical and Data Reporting Protocols" for inter-connection settlement revenue metering equipment design requirements. Per the SPP Market Protocol Document, the inter-connection revenue metering design requirements must be met for all new installations.

8.0 CONTROL AREA CERTIFICATION

An entity seeking to be recognized as a Control Area operating within SPP must be a member of SPP and must attain and maintain Control Area certification. Control Area certification will be performed by SPP pursuant to NERC approved Control Area Criteria and certification procedures to be developed and maintained by the Operatiing Reliability Working Group. These certification procedures will be publicly available by posting on the SPP home page.

9.0 BLACK START

This document provides general guidelines to be followed in the event of a partial or complete collapse of the SPP bulk electric system. Quick implementation of each Balancing Authority/Transmission Operator restoration plan compiled according to this Criteria and the NERC Reliability Standards shall facilitate coordination between member Balancing Authorities/Transmission Operators and the SPP Reliability Coordinator and insure the earliest possible restoration of the electric system. It is impossible to predict all the possible combinations of system problems that may occur after a major electric system failure. It is therefore the responsibility of system operators to restore the electric system applying the general guidelines outlined in this document and in their respective detailed black start plans. Strict adherence to other SPP Criteria is also necessary for a prompt restoration of the electric system. Mutual assistance between members Balancing Authorities/Transmission Operators is highly encouraged. This assistance may include the sharing of black start units. The SPP Reliability Coordinator shall take an active role during electric system restoration as outlined in this Criteria. Each Balancing Authority/Transmission Operator shall have a readily accessible and sufficiently detailed, current restoration plan to assist in an orderly restoration. Restoration shall be aided by communicating to neighboring Balancing Authorities/Transmission Operators and the SPP Reliability Coordinator an accurate assessment of the network conditions throughout the restoration process. Communication shall be established between neighboring operation centers, power plants and the SPP. Mutual assistance and cooperation are essential during restoration activities to avoid reoccurrence of a partial or complete electric system collapse.

9.1 Responsibilities

SPP shall develop and maintain a Regional Black Start Capability Plan and a Regional Restoration Plan in accordance with NERC Reliability Standards. The Regional Black Start Capability Plan and Regional Restoration Plan will be reviewed on an annual basis to ensure the plans maintain effectiveness and accuracy. It is the responsibility of SPP Staff to review and update the plans as required and to bring such proposed updates to the Operating Reliability Working Group (ORWG) for their review and approval. The annual review and any proposed updates are to be submitted to the ORWG no later than April 1.

9.1.1 Members

Each Balancing Authority/Transmission Operator shall develop and maintain a detailed internal black start plan. Each Balancing Authority/Transmission Operator shall review their black start plan annually and shall provide SPP with the latest version of their black start plan whenever changes are made or as requested by SPP Staff. Transmission Operators shall prepare a plan in cooperation with their responsible Balancing Authority designed to assist and coordinate with the Balancing Authority's plan This applies to cogeneration facilities and independent power producers. A copy of this plan shall be on file at the SPP office. Black start plans shall be verified by a minimum of simulation testing, although actual physical testing is highly encouraged where feasible. Members shall report any testing activities of black start plans to the ORWG.

Balancing Authorities and Transmission Operators shall train appropriate personnel in the implementation and execution of their black start plan

In the event of an electric system collapse, each Balancing Authority/Transmission Operator shall use the following items as guiding principles for the restoration process.

a. Provide assistance to any and all SPP Balancing Authorities and Transmission Operators as abilities allow, with priority given to the restoration of inter-system bulk electric system ties
b. Make adjustments to interchange schedules between affected areas as necessary to facilitate restoration efforts
c. Take immediate steps to initiate internal restoration plans
d. Supply neighboring Balancing Authorities/Transmission Operators and the SPP Reliability Coordinator with information on network status
e. Coordinate with neighbors the re-connection of Balancing Areas and/or islands.
f. If it becomes apparent that the emergency is of regional magnitude, the focus of restoration action shall shift from individual Balancing Area priorities to bulk network priorities. Priority to a neighboring Balancing Authority/Transmission Operator load may be necessary in order to benefit the overall strength of the bulk

electric system. As generation and transmission facilities become available, systematic restoration of network load shall be initiated with respect to priorities

g. Generation should be made available to all regional utilities for system and customer load restoration as recommended by the SPP Reliability Coordinator

9.1.2 SPP Reliability Coordinator

The SPP Reliability Coordinator shall be familiar with each Balancing Authority/Transmission Operator black start plan that is on file. In the event of a failure of the bulk electric system, the SPP Reliability Coordinator personnel shall take the following action.

a. The SPP Reliability Coordinator has the authority to temporarily suspend normal energy scheduling practices and to restore those practices once an operating emergency has been mitigated.
b. The SPP Reliability Coordinator should recommend sharing of generation available to all regional utilities for system and customer load restoration.
c. Maintain continuous surveillance of the status of the networks of all member Balancing Authorities (refer to section 9.4 for information required).
d. Act as a central information collection and dissemination point for Balancing Authorities/Transmission Operators.
e. Communicate with other regional offices, NERC and the Federal Emergency Management Administration
f. Communicate/recommend the need for assistance to appropriate Balancing Authorities/Transmission Operators.
g. The SPP Reliability Coordinator shall approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points.
h. The SPP Reliability Coordinator shall expect notification of Balancing Authority status. It is necessary that this information be recorded and shared with all Balancing Authorities/Transmission Operators. Based on this information, the SPP Reliability Coordinator shall immediately assess electric system conditions and status of communication facilities and inform all Balancing Authorities of the extent of the blackout (refer to section 9.4 for information required).

9.2 Elements of Balancing Authority/Transmission Operator Black Start Plans

Each Balancing Authority/Transmission Operator shall maintain a black start plan that is consistent with the NERC Reliability Standards. All plans and procedures shall be readily available to system operators, plant operators and the SPP Office. System operators shall review these documents on a regular basis It is suggested that Balancing Authority/Transmission Operator black start plans include the following elements.

a. Philosophies and strategies for Balancing Area restart
b. Identification of the relationships and responsibilities of the personnel necessary to the restoration
c. Identification of black start resources including generating unit resources, sufficient fuel resources, transmission corridors or paths, communication resources and power supplies, mutual assistance arrangements
d. Contingency plans for failed resources
e. Identification of critical load requirements
f. Identification of special equipment requirements
g. Provisions for training and documentation of training for personnel
h. Provisions for simulating and where practical, actual testing and verification of the resources and procedures
i General instructions and guidelines for system operators, plant operators, communications personnel, and transmission and distribution personnel
j. Provisions for public information
k. Synchronization Guidelines including operating instructions and procedures for synchronizing areas as may be dictated in the restoration plan
l. The functions to be coordinated with neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators
m. Notifications to neighboring Reliability Coordinators, Balancing Authorities, Transmission Operators, and other operating entities as phases of the restoration plan are implemented

Appendix 4 contains a list of items to be considered in the restoration process that may be used in the development or review of black start plans.

9.3 Restoration Priorities

The following actions for system restoration shall be considered by each Balancing Authority and assigned proper sequence and priority.

a. Stabilization of generating units
b. Restoration of inter-system and intra-system bulk electric system ties
c. Restoration and maintenance of intra- and inter-system communication facilities and networks
d. Assessment of Balancing Area condition and SPP electric system condition
e. Contact with public information agencies (Emergency Broadcasting System) to request the broadcasting of pre-distributed appeals and instructions
f. Restoration of units with black start capability
g. Providing service to critical electric system facilities
h. Connection of islands taking care to avoid reoccurrence of a partial or complete system collapse and equipment damage
i. Restoration of service to critical customer loads
j. Restore service to the remaining customers

9.4 Information Communication

Reliable communication between Balancing Authorities/Transmission Operators and SPP Reliability Coordinator will be the key to a safe and timely restoration following a collapse of the SPP network. As part of the initial assessment after a partial or complete system blackout, communication facilities shall be tested and verified. System operators shall establish communication within their area with special emphasis given to power plants and neighboring members. To expedite the recovery process, the SPP Emergency Communication Network (satellite phones) shall be used to convey appropriate information to members. **Balancing Authorities/Transmission Operators shall be prepared to communicate their status once an hour, or when polled by the SPP Reliability Coordinator** Only after voice communication paths have been established shall efforts be directed to re-establishing data communication paths. System status conditions to be surveyed include but are not limited to the following items.

a. Areas of the electric system that are de-energized
b. Areas of the electric system that are functioning
c. Amount of generation and generating reserve available in functioning areas

d. Power plant availability and time required to restart

e. Status of transmission breakers and sectionalizing equipment along critical transmission corridors, and at power plants

f. Status of transmission breakers and sectionalizing equipment at tie points to other areas

g. Status of fuel supply from external suppliers

h. Under-frequency relay operation

i. Relay flags associated with circuits tripped by protective relays

j. Status of communication systems

10.0 EMERGENCY COMMUNICATION

Dependable communication between members is critical to maintaining a reliable bulk electric system. As part of the initial assessment following a network disturbance or after a partial or complete blackout, communication facilities shall be tested and verified. Control Area operators shall establish communication with neighboring members and the SPP Reliability Authority. Control area operators shall establish contact with power stations.

10.1 SPP Emergency Communication Network

Should problems be encountered with any primary communication facilities, the SPP Emergency Communication Network shall be used to convey the appropriate information. Communication is vital to an orderly recovery. Priority should be given to establishing voice communication paths prior to re-establishing data communication paths. The SPP Emergency Communication Network is comprised of Satellite Phones located at each Control Area operating center. General information and operational instructions for these phones is contained in Appendix 3. During emergency conditions requiring the use of the SPP Emergency Communication Network, the Reliability Authority shall initiate a Group Call and quickly determine the extent of the interruption. Operating personnel shall keep conversations concise to keep channels clear. It is important in emergency situations for system operators to be familiar and comfortable with the phone operation. Each Control Area shall participate in the weekly test of the SPP Emergency Communication Network. Each Control Area system operator and the SPP Reliability Authority should become familiar with the operation of the phone. The Reliability Authority shall instigate and monitor this testing and training process.

10.2 Information Priority During Emergencies

System status conditions to be surveyed include but are not limited to the following items:

a. Areas of the electric system which are de-energized,

b. Areas of the electric system which are functioning,

c. Amount of generation and generating reserve available in functioning areas,

d. Power plant availability and time required to restart,

e. Status of transmission breakers and sectionalizing equipment along critical transmission corridors, and at power plants,

f. Status of transmission breakers and sectionalizing equipment at tie points to other areas,

g. Status of fuel supply from external suppliers,

h. Under-frequency relay operation,

i. Relay flags associated with circuits tripped by protective relays.

j. Status of communication systems.

11.0 SYSTEM DISTURBANCE REPORTING

The purpose of this Criteria is to establish uniform procedures for reporting system disturbances. The Disturbance Assessment Working Group is responsible for reviewing system disturbances or unusual adverse operating conditions for lessons to be learned. It is necessary that information about such events be provided promptly and completely to SPP.

11.1 Reporting Requirements

Any disturbance that is described by one or more of the following criteria shall be reported.

a. Loss of 100 MW of load or more than half of the pre-disturbance load, whichever is less, for more than 15 minutes. Members with peak loads of 3000 MW or greater shall report loss of 200 MW load.

b. Interruption of service to over 50,000 customers or more than half of the total customers, whichever is less, for more than three hours.

c. Cascading outages.

d. Equipment or facility failure that affects the adequacy or reliability of the bulk power supply system. An example would be a failure which causes an extended unscheduled power import.

e. Voltage reduction or public appeals to maintain continuity of bulk power supply system.

f. "Near misses" shall also be reported if they provide a "lesson to be learned" or might have been a reportable disturbance under different circumstances.

g. Frequency disturbances of 0.05 Hz or more.

11.2 Report Types

11.2.1 First Notification

System operators shall notify SPP as soon as possible, but no later than 24 hours of a reportable disturbance. This report may be by telephone or preferably through the SPP Computer Communication System. The first notification shall briefly describe the nature of the disturbance and expected restoration time.

11.2.2 Power System Major Disturbance Report

Within 3 days a disturbance report shall be sent to the Disturbance Assessment Working Group Chair containing basic information on time and nature of the incident.

11.2.3 Oral Report

The member(s) involved and the Disturbance Assessment Working Group shall determine if a report should be made at the next semi-annual Engineering and Operating Committee meeting.

11.2.4 US DOE/EP Power System Emergency Report

The Power System Emergency Reporting Procedures IE-0071 is independent of any SPP report. However, copies of form IE-417 can be sent to the SPP President and the Disturbance Assessment Working Group Chair when appropriate.

11.2.5 Detailed Disturbance Analysis Report

The analysis can vary widely in scope depending on the nature of the disturbance. The report shall contain the following information: Pre-disturbance conditions, Disturbance, Restoration, Conclusions, and Recommendations. The report shall also contain any or all of the following technical data as may be necessary: Chronological sequence of events, Oscillographs, Meter charts, and One line diagrams or maps

11.2.6 Report Submitted to NERC

The Disturbance Assessment Working Group shall review major disturbances of national interest within SPP and distribute reports to the NERC Disturbance Analysis Working Group. Inquiries from NERC shall be directed to the member(s) involved. Disturbance reporting is covered in NERC Operating Guide II.G. The NERC Disturbance Analysis Working Group uses 10 topic categories in their analysis which can serve as a checklist for individual members to use: Future Bulk Power System Planning, Bulk Power Supply Facilities, Relaying, System Operating Control & Communications Personnel, Operating Personnel, Near Term Operational Planning, System Reserve Response, Preventative Maintenance, Load Relief, and Restoration.

12.0 ELECTRICAL FACILITY RATINGS

12.1 Rating of Generating Equipment

To provide a basis for comparing operating margin of various entities and to assure reasonable distribution of the margin, generating equipment shall be uniformly and consistently rated to permit accurate planning. Procedures are herein established for rating generating units and establishing a system of records so that changes in capacity during the life of the equipment can be recognized. These procedures define the framework under which the ratings are to be established while recognizing the necessity of exercising judgment in their determination. The terms defined and the ratings established pursuant to these procedures shall be used for SPP purposes, including determining capacity margins for both planning and operating purposes, scheduling maintenance, and preparation of reports of other information for industry organizations, news media, and governmental agencies. These ratings are not intended to restrict daily operating practices associated with SPP operating reserve sharing, for which more dynamic ratings may be necessary. Each member shall test its generating equipment in accordance with the procedures contained herein. On the basis of these tests summer and winter net capability ratings for each generating unit and station on the member's electric system shall be established. This net capability is referenced in many NERC documents as net dependable capacity, that is the maximum capacity a unit can sustain over a specified period modified for seasonal limitations and reduced by the capacity required for station service or auxiliaries. The summer net capability of each unit may be used as the winter net capability without further testing, at the option of the member. As a minimum, each member shall conduct tests on all its generating equipment which is designated as a part of the resource for supplying its own peak load and minimum capacity margin requirement of this Criteria. The seasonal net capabilities, gross capabilities, and auxiliary loads shall be furnished to SPP for all existing generating units and upon installation of new generating units and shall be revised at other times when necessary. Members shall annually report the seasonal net generating unit capability in conjunction with the Department of Energy 411 Report data gathering effort. During the capability test the net capability shall be reported. Additionally, the unit's gross capability and auxiliary load shall be reported. The gross capability and auxiliary load shall be determined from the test or using such methods as use of manufacturer data, commissioning data, performance tracking, etc. Data used to determine net capability shall be obtained from testing.

12.1.1 Capability Test

Capability Tests are required to demonstrate the claimed capability of all generating units, excluding run-of-the-river hydroelectric plants and wind plants. During a Capability Test, a unit shall generate its rated net capability for a specified Test Period following a specified Settling Period. The length of these periods is determined by the type and size of unit. The unit will be within 5% of its rated capability throughout the Settling Period. Only minor changes in unit controls shall be made during this time as required to bring the unit into normal, steady-state operation. The following table specifies the duration of these periods. The reduced duration tests on the specified unit types are generally considered to be a fair and practical demonstration of unit capability. If operating experience for a given unit suggests otherwise, the system shall use this experience in establishing the time periods or use the periods in the table associated with large steam units.

Unit Type	Settling Period	Test Period
Steam > 100 MW net	2.0 hours	2.0 hours
Steam < 100 MW net	1.0 hour	1 0 hour
All other units	0.0 hour	1.0 hour

12.1.2 Operational Test

An Operational Test is used to demonstrate the ability of a generating unit to be loaded to its nominal rating. Operational tests shall be conducted at a minimum of 90% of claimed summer capability for a minimum of 1 hour. Any normal operating hour with the unit at or above 90% of claimed capability may be deemed an Operational Test.

12.1.3 Frequency of Testing

Summer Capability Tests shall be conducted once every 3 years. If the winter capability rating is greater than summer, winter tests shall also be conducted once every 3 years. Operational Tests shall be conducted once every year during the summer season. New units or units undergoing a physical or operational modification which could impact capability shall be given a capability test.

12.1.4 Rating and Testing Conditions

Ambient conditions at the time of running capability tests shall be recorded so that appropriate adjustments can be made when establishing seasonal capabilities. Conditions to be recorded are: dry-bulb temperature, wet-bulb temperature, barometric pressure, and condenser cooling water inlet temperature. Summer Capability Tests are to be conducted at an ambient temperature within 10 degrees Fahrenheit of Rating dry-bulb temperature

Winter Capability Tests are to be conducted at an ambient temperature equal to or greater than the minimum dry-bulb temperature for winter testing and rating defined in paragraph 2.3.5.2.g.

12.1.5 Procedures For Establishing Capability Ratings

12.1.5.1 External Factors

a. Units dependent upon common systems which can restrict total output shall be tested simultaneously.

b. When the total output of a member's system is reduced due to restrictions placed upon the output of individual generating units through the operation of the Clean Air Act, or similar legislation, then the total of the individual unit ratings of a member's generating resources shall not exceed the modified system capacity.

c. The fuel used during testing shall be the general type expected to be used during peak load conditions or adjustments made to test data if an alternate fuel is used.

d. Net Capability is the net power output which can be obtained for the period specified on a seasonally adjusted basis with all equipment in service under average conditions of operation and with the equipment in an average state of maintenance. Deductions from net capability shall not be made for equipment temporarily out of service for normal maintenance or repairs.

e. The seasonal net capability shall be determined separately for each generating unit in a power plant where the input to the prime mover of the unit is independent of the others, except that in the event multiple unit plant capability is limited by fuel limitations, transmission limitations or other auxiliary devices or equipment, each unit shall be assigned a rating by apportioning the combined capability among the units. The seasonal net capability shall be determined as a group for common header sections of steam plants or multiple unit hydro plants, and each unit shall be assigned a rating by apportioning the combined capability among the units.

12.1.5.2 Seasonality

a. The summer season is defined by the months June, July, August and September. The winter season is defined by the months December, January, February, and March. The adjustments required to develop seasonal net capabilities are intended to include seasonal variations in ambient temperature, condenser cooling water temperature and availability, fuel changes, quality and availability, steam heating loads, reservoir levels, scheduled reservoir discharge, and wind speed.

b. The total seasonal net capability rating shall be that available regularly to satisfy the daily load patterns of the member and shall be available for a minimum of four continuous hours taking into account possible fuel curtailments and thermal limits.

c. The seasonal net capability of each generating unit shall be based upon a set of conditions, referred to as the "Rating Conditions" for that unit. This set of conditions is determined by the geographical location of the unit, and is composed of three or four factors, depending upon the type of unit. The three factors which can affect most generating units are: Ambient dry-bulb temperature, Ambient wet-bulb temperature and Barometric pressure. Condensing steam turbines which obtain condenser cooling water from a lake, river, or comparable source have a fourth factor: Condenser cooling water source temperature.

d. The Rating dry-bulb and wet-bulb temperatures shall be obtained from weather data provided in the most recently published American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) <u>Fundamentals Handbook, Chapter 27 Climatic Design Information</u> The handbook is published every four years; 1997, 2001, etc , and is based on 15 years of historical weather data where available. If the generating station is within 30 miles of the nearest weather station reported in the Handbook, then these temperatures will be those for the nearest station. For all other stations, rating temperatures shall be determined by interpolating between weather stations using plant latitude and longitude. The steps to be used for interpolating weather data and correcting for elevation are presented in SPP Criteria Appendix 2.

e. If experience for a given unit suggests otherwise, members may optionally use their own site specific temperature data if accurate hourly data is available to allow calculation of the temperature levels as defined in the Criteria. Site specific data shall contain both dry-bulb and wet-bulb temperatures.

f. Temperatures for summer rating of equipment should be taken from Handbook Table 1B: Cooling and Dehumidification Design Conditions - Cooling DB/MWB for 0.4% DB (dry-bulb) and MWB (mean wet-bulb) (Column 2a and 2b, respectively) According to the 2001 Handbook Page 27.2, "The 0.4% annual value is about the same as the 1.0% summer design temperature in the 1993 ASHRAE Handbook." In older Handbooks, the dry-bulb temperature for summer rating of equipment shall be taken as that which is equaled or exceeded 1% of the total hours during the months of June through September for the plant's geographical location. The wet-bulb temperature for the summer rating shall be the "mean coincident wet-bulb" temperature corresponding to the above dry-bulb temperature.

g. The temperature for winter rating of equipment should be taken from Handbook Table 1A: Heating and Wind Design Conditions-United States - Heating Dry Bulb 99% (Column 2b). According to the 2001 Handbook Page 27.3, "Annual 99.6% and 99.0% design conditions represent a slightly colder condition than the previous cold season design temperatures, although there is considerable variability in this relationship from location to location." In older Handbooks, the minimum dry-bulb temperature for winter testing and rating shall be taken as that which is equaled or exceeded 99% of the total hours during the months of December through February (per Handbook definition) for the plant's geographical location. The wet-bulb temperature is not significant for the winter rating and can be disregarded.

h. Standard barometric pressure for a plant site shall be determined for each plant elevation from the equation provided in Appendix 2.

i. For those units using a lake or river as a source of condenser cooling water, the summer standard inlet temperature is the highest water inlet temperature during the hottest month of the year, averaged over the past ten years.

j. Ambient wet-bulb temperature and condenser cooling water temperature are generally not significant factors in adjusting cold weather capability of generating units. Shall special situations arise in which these temperatures are required, reasonable estimates for temperatures occurring coincidentally with the winter rating dry-bulb temperature as defined in the Criteria shall be used.

12.1.5.3 Rating Adjustments

a. The rated net capability of a unit may be above or below the actual tested net generation as a result of adjustments for Rating Conditions, with the exception of units with winter season ratings greater than their summer rating. For these units, the winter season rated net capability shall be no greater than the actual tested net generation. No rating adjustment for ambient conditions shall be made

b. Seasonal net capability shall not be reduced to provide regulating margin or spinning reserve. It shall reflect operation at the power factor level at which the generating equipment is normally expected to be operated over the daily peak load period.

c. Extended capability of a unit or plant obtained through bypassing of feed-water heaters, by utilizing other than normal steam conditions, by abnormal operation of auxiliaries in steam plants, or by abnormal operation of combustion turbines or diesel units may be included in the seasonal net capability if the following conditions are met, a) the extended capability based on such conditions shall be available for a period of not less than four continuous hours when needed and meets the other restrictions, and b) appropriate procedures have been established so that this capability shall be available promptly when requested by the system operator.

d. The seasonal net capability established for nuclear units shall be determined taking into consideration the fuel management program and any restrictions imposed by governmental agencies.

e. The seasonal net capability established for hydro electric plants, including pumped storage projects, shall be determined taking into consideration the reservoir storage program and any restrictions imposed by governmental agencies and shall be based on median hydro conditions.

f. The seasonal net capability established for run-of-the-river hydroelectric plants shall be determined using historical hydrological data on a monthly basis.

g. The net capability established for wind plants shall be determined on a monthly basis, as follows:

i. Assemble up to the most recent ten years, with a minimum of the most recent five years, of hourly net power output (MW) data, measured at the system interconnection point. Values may be calculated from wind data, if measured MW values are not yet available. Wind data correlated with a reference tower beyond fifty miles is subject to Generation Working Group approval. For calculated values, at least one year must be based on site specific wind data.

ii. Select the MW values occurring during the top 10% of load hours for the SPP region for each month (e.g., 72 hours for a typical 30 day month).

iii. Select the MW value that can be expected from the plant at least 85% of the time.

iv A seasonal or annual net capability may be determined by selecting the appropriate monthly MW values corresponding to the host control area's peak load month of the season of interest.

v. The net capability calculation shall be updated at least once every three years.

12.1.6 Reactive Capability Verification

12.1.6.1 Verification Required Every Five Years

Initial verification of the gross and net reactive capabilities (leading and lagging) of each generating unit and synchronous condenser (hereinafter referred to as "unit") within the SPP footprint shall be provided to SPP on or before the in-service date of the unit Thereafter, documentation verifying the unit's gross and net leading and lagging reactive capability shall be provided on or before the fifth anniversary of the most recent date that verification documentation was submitted. In addition, documentation verifying gross and net reactive capabilities shall be provided after repairs or equipment changes that may affect reactive capability.

12.1.6.2 Entity Responsible for Verification

The unit's operator shall be the entity responsible for verification of the gross and net leading and lagging capabilities of the unit. This data shall be provided to the SPP Member who is responsible for modeling the unit in power flow and stability models. Data should be provided using Appendix 10, "Unit Reactive Limits (Lead and Lag) Verification FORM".

12.1.6.3 Leading and Lagging Capabilities Verified

Both the leading capability of the unit (the ability of the unit to absorb megavolt-amps reactive (MVAR) from the electric grid) and the lagging capability of the unit (the ability of the unit to inject MVAR into the electric grid) shall be verified as specified in section 12.1.6.4.

12.1.6.4 Method of Verification

Verification of a unit's gross and net reactive capabilities may be demonstrated:

(a) by submitting documentation showing the maximum leading or lagging MVAR produced by the unit during actual operations; or

(b) by submitting an engineering analysis that demonstrates the expected maximum leading and lagging MVAR of the unit; or

(c) by submitting commissioning data provided that no major modifications have been performed to the unit that would affect its MVAR rating; or

(d) by verifying the unit capability as further described in this criteria. In the event a unit is incapable of being verified as specified in criteria, then the unit's gross and net reactive capabilities must be demonstrated using one of the other methods set forth above. If testing is used to verify reactive capabilities, there is no limitation on the time period between the test for leading capability and the test for lagging capability, provided that each of these capabilities are tested/validated at least once every five years.

12.1.6.5 Reactive Capability Test/Verification

12.1.6.5.1 Test/Verification Objective.

(a) Gross and net leading reactive capability. Under system conditions that are likely to induce the maximum leading response (i.e., the point at which the unit absorbs the largest quantity of MVAR from the electric grid), obtain one data point that shows the gross and net leading reactive capability versus energy production (real power) of the unit.

(b) Gross and net lagging reactive capability. Under system conditions that are likely to induce the maximum lagging response (i.e., the point at which the unit injects the largest quantity of MVAR into the electric grid), obtain one data point that shows the gross and net lagging reactive capability versus energy production (real power) of the unit.

These points shall reflect either the maximum leading or lagging MVAR at or near maximum real power or at such other real power output level as may be specified in the interconnect agreement with the transmission owner.

12.1.6.5.2 Test/Verification Conditions.

As discussed in this section, conditions on the grid should be such that the reactive response of the unit will approach the unit's maximum. System conditions for leading and lagging capability verification are diametrically opposed (leading capability is demonstrated during light loading conditions while lagging capability is demonstrated during heavy loading conditions). Therefore, a complete verification for both leading and lagging capabilities will require collection of data points during different seasons.

(a) Unit parameters During the verification, parameters for unit load, unit temperature, and unit pressure (hydrogen, boiler, etc.) should be as close as practicable to those experienced during normal operating conditions, or as specified by the unit manufacturer.

(b) Power factor and grid conditions. The validation should be conducted at the unit's power factor as specified in the Interconnection Agreement. If the Interconnection Agreement does not specify the unit's power factor, then the verification should be conducted in a manner that will determine the maximum leading or lagging MVAR the unit is capable of producing while it is operating at or near its maximum real power capability. The conditions that will provide this result for leading reactive capability involve light system loads and light transmission line loading during the Spring or Fall. The conditions that will yield this result for lagging reactive capability involve peak or near peak Winter or Summer conditions. When possible, other synchronous machines or power system components should be used to obtain the most advantageous terminal voltage during the verification. Additionally, communication with the transmission provider may help optimize verification conditions.

(c) Data collection point. Unit verification data shall be collected at the point of interconnection to the transmission system.

12.1.6.5.3 Test/Verification procedure.

(a) Procedure for Verification of Unit Reactive Lagging Limits While operating in a steady state mode at gross and net dependable mega-watt (MW) capability (near rated output), raise excitation in automatic voltage control until one of the following conditions occurs:

   i. The 100% megavolt-amp (MVA) rating of the machine is reached (reach capability curve);

ii. Rated field current or field voltage is reached;
iii. Terminal voltage limit is reached (105-110%, depending on unit);
iv. Generator temperature limits are reached;
v. The maximum over-excitation limiter is reached or alarms;
vi. The maximum reference adjuster travel or limit is reached;
vii. Maximum auxiliary bus voltage is reached; or
viii. Transmission constraints prevent any further increase in lagging MVAR.

At the point that one of the above conditions is met, maintain unit output for a minimum of 15 minutes, and then record the data specified in Appendix 10, "Unit Reactive Limits (Lead and Lag) Verification FORM".

(b) Procedure for Verification of Unit Reactive Leading Limits. While operating in a steady state mode at or near gross and net dependable MW capability, lower excitation in automatic voltage control until one of the following conditions occurs:

i. Under-excitation limiters (UELs) are activated;
ii. 100% MVA rating is reached;
iii. Generator temperature limits are reached;
iv. Minimum reference adjuster travel or limit is reached;
v. Minimum auxiliary bus voltage is reached;
vi. Minimum terminal voltage is reached; or
vii. Transmission constraints prevent any further increase in leading reactive power.

At the point that one of the above conditions is met, maintain unit output for a minimum of 15 minutes, and then record the data specified in Appendix 10, "Unit Reactive Limits (Lead and Lag) Verification FORM".

12.1.6.6 Test/Verification Results.

A validation will be rejected if the unit is verified under conditions other than those specified in this criteria. If a test/verification is rejected, the unit must either be revalidated within the next 12 months or gross and net reactive capability demonstrated through one of the alternative methods specified in section 12.1.6.4.

12.2 Rating of Transmission Circuits

Each SPP member shall rate transmission circuits operated at 69 kV and above in accordance with this criteria. A transmission circuit shall consist of all elements load carrying between circuit breakers or the comparable switching devices. Transformers with both primary and secondary windings energized at 69 kV or above are subject to this criteria. All circuit ratings shall be computed with the system operated in its normal state (all lines and buses in-service, all breakers with normal status, all loads served from their normal source). The circuit ratings will be specified in "MVA" and are taken as the minimum ratings of all of the elements in series. The minimum circuit rating shall be determined as described in this criteria and members shall maintain transmission right-of-way to operate at this rating. However, SPP members may use circuit ratings higher than these minimums. Each element of a circuit shall have both a normal and an emergency rating. For certain equipment, (switches, wave traps, current transformers and circuit breakers), these two ratings are identical and are defined as follows:

a. NORMAL RATING: Normal circuit ratings specify the level of power flow that facilities can carry continuously without loss of life to the facility involved.

b. EMERGENCY RATING: Emergency circuit ratings specify the level of power flow that a facility can carry for the time sufficient for adjustment of transfer schedules, generation dispatch, or line switching in an orderly manner with acceptable loss of life to the facility involved.

At a minimum, each member shall compute summer and winter seasonal ratings for each circuit element. The summer season is defined by the months June, July, August and September. The winter season is defined by the months December, January, February and March. The seasonal rating shall be based upon an ambient temperature (either maximum or average) developed using the methodology described in Appendix A. A member may elect to compute a third set of seasonal ratings for the remaining months of the year (April, May, October and November). If that election is not made, summer ratings shall be used for these remaining months.

12.2.1 Power Transformer

Power transformer ratings are discussed in ANSI/IEEE C57.92-1981, IEEE Guide for Loading Mineral-Oil-Immersed Power Transformers Up to and Including 100 MVA with 55°C or 65°C

Average Winding Rise and in IEEE Standard C57.115-1991, IEEE Guide for Loading Mineral-Oil-Immersed Power Transformers Rated in Excess of 100 MVA (65EC Winding Rise). Every transformer has a distinct temperature rise capability used in setting its nameplate rating (either 55 °C or 65°C). These temperature rise amounts reflect the average winding temperature rise over ambient that a transformer may operate on a continuous basis and still provide normal life expectancy.

12.2.2.1 Normal Rating

The normal circuit rating for power transformers shall be its highest nameplate rating The nameplate rating shall include the effects of forced cooling equipment if it is available. For multi-rated transformer (OA/FA, OA/FA/FA, OA/FOA/FOA, OA/FA/FOA) with all or part of forced cooling inoperative, nameplate rating used is based upon the maximum cooling available for operation. Normal life expectancy will occur with a transformer operated at continuous nameplate rating.

12.2.1.2 Emergency Rating

When operated for one or more load cycles above nameplate rating, the transformer insulation deteriorates at a faster rate than normal. The emergency circuit rating for power transformers shall be a minimum of 100% of its highest nameplate rating. Member systems may use a higher emergency rating if they are willing to experience more transformer loss-of-life.

12.2.1.3 Loss of Life

Using Table 3 in ANSI/IEEE C57 92-1981, a 65°C rise transformer can operate at 120% for an 8 hour peak load cycle and will experience a 0.25% loss of life. If a 65°C rise transformer experiences 4 incidents where it operates at or below 120% for an 8 hour peak load cycle, it will still be within the target of 1% loss of life per year. Using Table 5 in ANSI/IEEE C57.92-1981, a 55°C rise transformer can operate at 123% for an 8 hour peak load cycle and will experience a 0.25% loss of life. Likewise, if a 55°C rise transformer experiences 4 incidents where it operates at or below 123% for an 8 hour peak load cycle, it will still be within the target of 1% loss of life per year.

12.2.1.4 Ambient Temperature

Average ambient temperature is an important factor in determining the load capability of a transformer since the temperature rise for any load must be added to the ambient to determine operating temperature. Transformers designed according to ANSI standards use a 30°C average ambient temperature (average temperature for 24 consecutive hours) when setting nameplate rating Transformer overloads can be increased at lower average ambient temperatures and still experience the same loss of life. This allows seasonal ratings with higher normal and emergency ratings. However, this circuit rating criteria does not call for seasonal transformer ratings. Using Tables 3 and 5 in ANSI/IEEE C57.92-1981, transformers can be loaded above 110% and experience no loss of life when the average ambient temperature is below 78°F. By not having seasonal ratings, the four occurrences that contribute to loss of life are limited to days when the average ambient temperature exceeds 78°F. The Power Transformer Rating Factors include:

a. Nameplate rating, normal loss of life for 55°C and 65°C rise transformers with cooling equipment operating.
b. Average ambient temperature, 30°C.
c. Equivalent load before peak load, 90% of nameplate rating.
d. Hours of peak load, 8 hour load cycle.
e. Acceptable annual loss of life, 1%.

12.2.2 Overhead Conductor

Overhead conductor ratings are discussed in IEEE Standard 738-1993, IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors. Ampacity values are to be determined using the fundamental heat balance equation outlined in the House and Tuttle method. Because of the amount and complexity of the equations, this method lends itself to computer application. The recommended computer programs to be used for this calculation either include the BASIC program listed in Annex A of IEEE Standard 738-1993 or an equivalent program, such as the DYNMAP program which is part of the EPRI TLWorkstation ™ software package. While tables and graphs may be convenient to use, they fail to take into account the geographic location of the line and often lack either the desired ambient temperature and/or the desired conductor temperature. The use of tables and graphs is not acceptable

12.2.2.1 Conductor Properties

Some computer programs used to compute ampacity values have a conductor property library whereby a user simply specifies the conductor code name and the program will search the conductor property file and select the proper input properties. Those using the BASIC program from Annex A of IEEE Standard 738-1993 or another computer program that does not have a conductor property library will obtain conductor properties from an appropriate data source (Aluminum Electrical Conductor Handbook, EPRI Transmission Line Reference Book 345 kV and Above, Westinghouse Transmission and Distribution Book, etc.).

12.2.2.2 Line Geographic Location

These factors specify the location of the line, its predominant direction and its predominant inclination. These numbers can either be line specific or they can represent a general line within the control area One ambient temperature shall be agreed upon for tie lines traversing several geographic areas and interconnections among different control areas.

12.2.2.3 Radiation Properties

The two radiative properties of conductor material are solar absorptivity and infrared emissivity.

Solar Absorptivity The fraction of incident solar radiant energy that is absorbed by the conductor surface. This value shall be between 0 and 1. Recommended values are given in the following tables:

COPPER CONDUCTORS	
Oxidation Level	**Absorptivity**
None	0.23
Light	0.5
Normal	0.7
Heavy	1.0

ALUMINUM CONDUCTORS	
Service Years	**Absorptivity**
0<5	0.43
. 5	1.00

Source: Glenn A. Davidson, Thomas E. Donoho, George Hakun III, P. W. Hofmann, T. E Bethke, Pierre R. H. Landrieu and Robert T. McElhaney, "Thermal Ratings for Bare Overhead Conductors", IEEE Trans., PAS Vol. 88, No.3, pp. 200-05, March 1969.

Infrared Emissivity The ratio of infrared radiant energy emitted by the conductor surface to the infrared radiant energy emitted by a blackbody at the same temperature. This value shall be between 0 and 1. Recommended values are given in tables below:

COPPER CONDUCTORS	
Oxidation Level	**Emissivity**
None	0.03
Light	0.3
Normal	0.5
Heavy	0.8

ALUMINUM CONDUCTORS	
Service Years	**Emissivity**
0	0.23
5-10	0 82
10-20	0.88
. 20	0.90

Source: W. S. Rigdon, H. E. House, R. J. Grosh and W. B. Cottingham, "Emissivity of Weathered Conductors After Service in Rural and Industrial Environments," AIEE Trans., Vol. 82, pp. 891-896, Feb. 1963.

12.2.2.4 Weather Conditions

Ambient temperature represents the maximum seasonal temperature the line may experience for summer and winter conditions. Appendix A contains a methodology to compute maximum ambient temperature. Wind speed is assumed at 2 ft/sec (1.4 mph) or higher. Wind direction is assumed perpendicular to the conductor.

12.2.2.5 Maximum Conductor Temperature

The selection of a maximum conductor temperature affects both the operation and design of transmission lines. Existing transmission lines were designed to meet some operating standard that was in effect at the time the line was built. That standard specified the maximum conductor temperature which maintained acceptable ground clearance while allowing for acceptable loss of strength. Over time, the required amount of ground clearance and the maximum conductor temperature needed to maintain acceptable ground clearance have changed. The changes are reflected in the revisions that have been made to the National Electric Safety Code (NESC) over the years. Although this Criteria specifies a maximum conductor temperature that could be met by current line design practices, consideration must be given to existing lines that were built according to an earlier standard. This Circuit Rating Criteria specifies a maximum conductor temperature (for both normal and emergency operating conditions) that shall be used for seasonal circuit ratings. For those existing lines that were designed to meet an earlier standard, it is the responsibility of the line owner to establish a rating that is consistent with the NESC design standards being practiced at the time the line was built. This Criteria specifies the use of maximum conductor temperatures that either maintain acceptable ground clearance requirements from earlier NESC's or meet the temperature requirements in section 3.6.2.6, whichever is lower.

12.2.2.6 Determination of Maximum Conductor Temperature

The maximum conductor temperature for normal ratings may be limited by conductor clearance concerns. Normal ratings are at a level where loss of strength is not a concern The maximum conductor temperature for emergency ratings have both conductor clearance and loss of strength concerns. By setting a maximum conductor temperature and the length of time a conductor may operate at this temperature, the maximum allowable loss of strength over the life of the conductor is prescribed. Unless conductor clearance concerns dictate otherwise, at least the following maximum conductor temperatures shall be used This allows for the efficient utilization of the transmission system while accepting minimal risk of loss of conductor strength during emergency operating conditions. These conductor temperatures are a result of the examination of SPP members practices.

	Maximum Conductor Temperature	
	Normal Rating	Emergency Rating
ACSR	85^{0}C	100^{0}C
ACAR	85^{0}C	100^{0}C
Copper	85^{0}C	100^{0}C
Copperweld	85^{0}C	100^{0}C
AAC	85^{0}C	100^{0}C
AAAC	85^{0}C	100^{0}C
SSAC	200^{0}C	200^{0}C
Note: Annealing of copper and aluminum begins near 100^{0}C.		

12.2.2.7 Hours of Operation at Emergency Rating

The effect of conductor heating due to operating at the maximum temperature during emergency conditions is cumulative. If a conductor is heated under emergency loading for 4 hours 8 times during the year, the total effect is nearly the same as heating the conductor continuously at the temperature for 32 hours. Using a useful conductor life of 30 years, the conductor will have been heated to the maximum temperature for 1000 hours. For an all aluminum conductor (AAC), this results in a 7% reduction from initial strength. Since the steel core of an ACSR conductor is essentially unaffected by the temperature range considered for emergency loadings, for an ACSR conductor, this results in a 3% reduction from initial strength. Both of these amounts are acceptable loss of strength. The daily load cycle for operating at the emergency rating shall not exceed 4 hours. This load cycle duration for conductors operating at the emergency rating is more restrictive than power transformers because power transformers have a delay in the time required to reach a stable temperature following any change in load (caused by a thermal lag in oil rise) and because seasonal ratings shall allow transmission lines to achieve a maximum conductor temperature throughout the year, not just days when the ambient exceeds 78°F.

12.2.3 Underground Cables

Ampacities are calculated by solving the thermal equivalent of Ohm's Law. Conceptually, the solution is simple, however the careful selection of the values of the components of the circuit is necessary to ensure an accurate ampacity calculation. The recognized standard for almost all steady-state ampacity calculations, in the United States, is taken from a publication, "The Calculation of the Temperature Rise and Load Capability of Cable Systems," by J.H. Neher and M.H. McGrath, 1957, hereafter referred to as the Neher-McGrath method The procedure is relatively simple to follow and has been verified through testing. In recent years, some of the parameters have been updated, but the method is still the basis of all ampacity calculations.

12.2.3.1 Cable Ampacity

Cable ampacity is dependent upon the allowable conductor temperature for the particular insulation being used. Conductor temperature is influenced by the following factors:

- Peak current and load-cycle shape;
- Conductor size, material and construction;
- Dielectric loss in the insulation;
- Current-dependent losses in conductor, shields, sheath and pipe;
- Thermal resistances of insulation, sheaths and coverings, filling medium, pipe or duct and covering, and earth;
- Thermal capacitances of these components of the thermal circuit;
- Mutual-heating effects of other cables and other heat sources; and
- Ambient earth temperatures.

Both steady-state and emergency ampacities depend upon these factors, although emergency ratings have a greater dependency upon the thermal capacitances of each of the thermal circuit components.

12.2.3.2 Conductor Temperature

The maximum allowable conductor temperature is 85EC for high-pressure fluid-filled (HPFF), pipe-type cables and 90EC for crosslinked, extruded-dielectric cables.

The table below summarizes allowable conductor temperatures for different insulation materials.

Two values are given for each cable insulation. The higher temperature may be used if the thermal environment of the cable is well-known along the entire route, or if controlled backfill is used, or if fluid circulation is present in an HPFF circuit. The maximum conductor temperatures allowed under steady-state conditions are limited by the thermal aging characteristics of the insulation structure of the cable. For emergency-overload operating conditions, maximum conductor temperatures are also limited by the thermal aging characteristics. The temperature is also limited by the melting temperature range of the insulation structure of the cable, its deformation characteristic with temperatures, restraints imposed by the metallic shield, deformation characteristic of the jacket, and the decrease in ac and impulse strengths with increases in temperature.

Insulation Material	Maximum Temperature	
	Normal	Emergency
Impregnated paper (AEIC CS2-90 for HPFF and HPGF (AEIC CS4-79 for SCLF)	85^0C (75^0C)	105^0C for 100 hr 100^0C for 300 hr
Laminated paper-polypropylene (AEIC CS2-90)	85^0C (75^0C)	105^0C for 100 hr 100^0C for 300 hr
Crosslinked polyethylene (AEIC CS7-87)	90^0C (80^0C)	130^0C* cumulative for 1500 hr
Ethylene-propylene rubber (AEIC CS6-87)	90^0C (80^0C)	130^0C* cumulative for 1500 hr
Electronegative gas/spacer	Consult manufacturer for specific designs	
* This limit may need to be reduced to prevent damage due to thermal expansion of the insulation		

12.2.3.3 Ambient Temperature

The ambient temperature is measured at the specified burial depth for buried cables and the ambient air temperature is used for cables installed above ground. IEC Standard 287-1982 (2-5) recommends that in the absence of national or local temperature data the following should be used:

Climate	Ambient Air Temperature ^{0}C	Ambient Ground Temperature ^{0}C
Tropical	55	40
Sub-tropical	40	30
Temperature	25	20

The electrical resistance is composed of conductor dc resistance, ac increments due to skin and proximity effects, losses due to induced currents in the cable shield and sheath and induced magnetic losses in the steel pipe. Heat generated in the cable system will flow to ambient earth and then to the earth surface This heat passes through the thermal resistances of the cable insulation, cable jacket, duct or pipe space, pipe covering and soil. Adjacent heat sources, such as other cables or steam mains, will provide impedance to the heat flow and thus reduce cable ampacity. Further information concerning the components of the ampacity calculations are summarized in Appendix B and fully detailed in the EPRI Underground Transmission Systems Reference Book. An example calculation, from the EPRI book, is also provided in Appendix B.

12.2.4 Switches

Appendix C contains a discussion on developing ratings for switches. In general, switches have seasonal ratings that are a function of the maximum ambient temperature. A switch part class designation is used to differentiate loadability curves that give factors which can be multiplied by the rated continuous current of the switch to determine temperature adjusted normal and 4 hour emergency ratings. The summer normal and emergency switch ratings can be computed by selecting the appropriate loadability factor curve for the switch part class, reading the loadability factors that are appropriate for the summer maximum ambient temperature (40^{o}C or the summer maximum ambient temperature determined in Appendix A), and multiplying the continuous current ratings by the loadability factor. The switch winter normal and emergency ratings can be computed by multiplying the continuous current rating by the normal and emergency loadability factors that are appropriate for the winter maximum ambient temperature (0^{o}C or the winter maximum ambient temperature determined in Appendix A).

Appendix C contains loadability factor curves (both normal and emergency) for various switch part classes. The ANSI/IEEE standard referenced in Appendix C allows for emergency ratings to be greater than normal ratings. This Criteria does not require the emergency rating to be greater than the normal rating.

12.2.5 Wave Traps

Appendix D contains a discussion on developing ratings for wave traps. The two types of wave traps are the older air-core type and the newer epoxy-encapsulated type. In general, both types have a continuous current rating based on a 40°C maximum ambient temperature. Both types have a loadability factor that can be used to determine seasonal ratings that are a function of the maximum ambient temperature. However, the older air-core type has another loadability factor that can be used to determine a four-hour emergency rating that is also a function of the maximum ambient temperature. The newer epoxy encapsulated type does not have an emergency rating.

12.2.6 Current Transformers

Appendix E contains a discussion on developing ratings for current transformers. The two types of current transformers are the separately-mounted type and the bushing type. In general, both types have a continuous current rating based on a 30°C average ambient temperature.

12.2.6.1 Separately Mounted Current Transformers

The separately-mounted type has an ambient-adjusted continuous thermal current rating factor that can be multiplied by the rated primary current of the current transformer to determine seasonal ratings. Separately-mounted current transformers do not have emergency ratings.

12.2.6.2 Bushing Current Transformers

Bushing current transformers are subject to and influenced by the environment of the power apparatus in which they are mounted. Bushing current transformers can be located within circuit breakers and power transformers. Since bushing current transformers are subject to the environment within the power apparatus, they do not have ambient adjusted continuous thermal current rating factors. Rather, if the primary current rating of the ratio being used is less than the continuous current rating of the breaker or the power transformer, this restricts the breaker or power transformer to operate below its rated current which reduces the current transformer temperature. This allows the current transformer to be operated at a continuous thermal rating factor greater than 1.0. Having a bushing current transformer whose primary current rating of the ratio being used is less than the continuous current rating of the breaker or the power transformer is an unusual case. However, the formula to develop the rating factor for this case is located in Appendix E. Although bushing current transformers have some short-term emergency overload capability, it must be coordinated with the overall application limitation of the other equipment affected by the current transformer loading. Consequently, this criteria does not recognize an emergency rating for bushing current transformers.

12.2.7 Circuit Breakers

Appendix F contains a discussion on developing ratings for circuit breakers. This discussion centers on the use of specific circuit breaker design information to set seasonal and emergency ratings. This design information is not readily available to the owners of such equipment. To use the rating methodology discussed in Appendix F would require contacting the manufacturer for detailed design information for each circuit breaker being rated. Rather than doing that, this circuit rating criteria specifies that the nameplate rating shall be used for seasonal normal and emergency ratings. The nameplate rating is based on a maximum ambient temperature of 40°C. If a circuit breaker is found to be a limiting element in a circuit and is experiencing loadings that limit operations, a member system may pursue the methodology outlined in Appendix F to determine the circuit breakers seasonal normal and emergency rating.

12.2.8 Ratings of Series and Reactive Elements

The series transmission elements rating will be in amps, ohms, and MVA. The series transmission elements current (amps) rating will be taken as the minimum rating of all internal components (e.g., breakers) that are in series with the interconnected transmission circuit. Shunt reactive elements (e.g , capacitors, reactors) MVA ratings will be based on the nominal transmission interconnecting voltage.

The documentation of the methodology(ies) used to determine the rating of series and reactive elements shall be provided to SPP and/or NERC on request within five business days.

12.2.9 Ratings of Energy Storage Devices

The available real power rating, reactive power rating, control points, and availability of each electrical energy storage device will be provided to SPP upon request. The documentation of the methodology(ies) used to rate electrical energy storage devices shall be provided to SPP and/or NERC on request within five business days.

12.2.10 Circuit Rating Issues

12.2.10.1 Dynamic (Real Time) Ratings

The calculation of static thermal ratings specified in Section 3.6.2 uses worst case thermal and operational factors and therefore apply under all conditions. Often times, these worst case thermal and operational factors do not all occur at the same time Consequently, a static rating may understate the thermal capacity of the circuit. For operation purposes, some members have elected to monitor the factors that affect circuit ratings and use this information to set dynamic ratings. A member can develop and use a rating that exceeds the static thermal rating for operating purposes. The ratings developed by using this criteria are not intended to restrict daily operations but set a minimum rating that can be increased when factors for determining the equipment rating have changed. However, if transmission line ratings are changed dynamically, the required clearances shall still be met.

12.2.10.2 Non-Thermal Limitations

There may be instances when the flow on a transmission circuit is limited by factors other than the thermal capacity of its elements. The limit may be caused by other factors such as dynamics, phase angle difference, relay settings or voltage limited.

12.2.10.3 Tie Lines

When a tie line exists between two member systems, use of this criteria shall result in a uniform circuit rating that is determined on a consistent basis between the two systems. For tie lines between a SPP member and a non-member, the member shall follow this criteria to rate the circuit elements owned by them and shall coordinate the rating of the tie line with the non-member system such that it utilizes the lowest rating between the two systems.

12.2.10.4 Rating Inconsistencies

A member may have a contractual interest in a joint ownership transmission line whereby the capacity of the line is allocated among the owners. The allocated capacity may be based upon the thermal capacity of the line or other considerations. Members shall use good faith effort to amend their transmission line agreements to reflect the effects of new circuit ratings. There may exist other transmission agreements or regulatory mandates that use the thermal capacity of transmission circuits in allocation of cost and determination of network usage formulas (for example, the MW-mile in ERCOT). These agreements and mandates may specify a methodology and/or factors for computing thermal capacity used in the formulas. Since these amounts are only used in assignment of cost or usage responsibility and not in actual operations of the transmission system, there is no conflict with using a different set of ratings for this specific purpose.

12.2.10.5 Damaged Equipment

There may be instances when a derating of a transmission line element is required due to damaged equipment. The limit may be caused by such factors as broken strands, damaged connectors, failed cooling fans, or other damage reducing the thermal capability.

12.2.11 Reporting Requirements

Each member will administer this Criteria and will make available upon request the application of this Criteria for those facilities that impact another member (i.e. force them to curtail schedules due to line loadings, denies them access to transmission service or requires them to build new transmission facilities or pay opportunity costs to receive transmission service).

13.0 OPEN

14.0 TRANSMISSION LOADING RELIEF

14.1 Purpose

In the continuous operation of the bulk electric power network, certain procedures are necessary to involve those operating entities that impact overloaded facilities. Procedures are included for corrective action and mutual assistance during periods for which Transmission Loading Relief is necessary. These Criteria ensure SPP maintains a high level of reliability using standard procedures to relieve overloaded transmission circuits. The rating of transmission circuits is described elsewhere in SPP Criteria.

14.2 Definitions

14.2.1 Flowgate

A flowgate is a pre-defined proxy for network limitations representing thermal, voltage, and stability constraints of power transfer. Flowgates consist of one or more transmission circuits rated at 60 kV or above.

14.2.2 Transmission Circuit

A transmission circuit shall consist of all load-carrying elements between circuit breakers or comparable switching devices. Transmission circuit rating criteria is described in Criteria 12.

14.2.3 Interconnected Reliability Operating Limit

The North American Electric Reliability Council (NERC) defines Interconnected Reliability Operating Limit (IROL) as "The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages."

14.2.4 System Operating Limit

The North American Electric Reliability Council (NERC) defines System Operating Limit (SOL) as "The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
- Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)

- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)"

14.3 Daily Reliability Assessment

14.3.1 Control Area Data Reporting

Control Areas shall comply with SPP Criteria and NERC Reliability Standards regarding data reporting.

14.3.2 Overload Evaluation

Information collected shall be used by the Reliability Coordinator to evaluate transmission conditions for the current and next day. Single contingency analysis as well as other reviews shall be made daily The Reliability Coordinator shall report the daily results to SPP Control Areas.

14.3.3 Control Area Planning

Control Areas shall review the daily reliability assessment report. If the report indicates that anticipated conditions could result in excessive loading on a transmission circuit, Control Areas shall consider and plan for internal procedures that can be taken to prevent degradation of system reliability.

14.4 Transmission Loading Mitigation

14.4.1 Reliability Coordinator Responsibilities

14.4.1.1 Monitoring

The Reliability Coordinator will monitor the transmission system. Monitoring and appropriate control action will be performed to ensure the transmission system is operated so that instability, uncontrolled separation, cascading outages, or equipment damage will not occur as a result of the most severe single contingency. Flowgate flows will be closely monitored and compared to applicable SOLs and IROLs.

14.4.1.2 Weather Adjustment of Limits

Some flowgates or transmission circuits have static seasonal ratings that are developed using certain pre-determined weather condition assumptions (see Criteria 12). To the extent that certain weather conditions such as ambient temperature, wind speed, or wind direction are available, the Reliability Coordinator will coordinate with the Transmission Operator to appropriately adjust the SOLs for those flowgates during heavy loading conditions.

14.4.2 Control Area Responsibilities

Control Areas will monitor their own transmission systems for system reliability. They are responsible for identifying and addressing reliability problems and shall work with the Reliability Coordinator, as appropriate, to correct those problems. Control Areas can call for Transmission Loading Relief to relieve excessive transmission loading. Control Areas shall notify the Reliability Coordinator whenever internal procedures are implemented to relieve overloading.

14.4.3 Transmission Loading Relief Procedures

These procedures shall be implemented whenever the Reliability Coordinator or a Control Area observes excessive flows on a flowgate or other transmission circuit.

a. The Reliability Coordinator will verify actual real-time flow readings with the Control Area and compare against the applicable SOL and IROL for the flowgate or circuit.
b. The Reliability Coordinator will determine the contribution of transactions to the excessive loading and will convey the results of this assessment to the Control Area. This information will be used to determine if transaction curtailments or local control actions are necessary to relieve the excessive loading.
c. Upon request by the Control Area, the Reliability Coordinator will initiate a request for Transmission Loading Relief pursuant to NERC Reliability Standards
d. The Reliability Coordinator shall notify Control Areas and other Reliability Authorities of which scheduled interchange transactions, network service, and native load impacts are to be curtailed during the relief period. Control Areas shall acknowledge receipt of scheduled interchange transaction curtailment, curtail the transactions and/or redispatch generation, as appropriate, for the line loading problems
e. The Reliability Coordinator shall continuously monitor flows, dispatch, and transactions throughout the period of excessive loading. Any request for Transmission Loading Relief will be canceled when the condition of excessive loading no longer exists and termination of Transmission Loading Relief is not anticipated to cause renewed line loading problems.
f. Rerouting curtailed schedules through another path is prohibited.

14.5 Subsequent Overload Conditions

In the event of simultaneous or concurrent requests for Transmission Loading Relief, the same procedures will be used with due consideration being given to all existing conditions.

14.6 Curtailment Reports

Reports shall be posted on an hourly basis during any period of Transmission Loading Relief. Daily and monthly summary reports shall also be distributed. These reports shall be used as verification of associated energy schedules.

14.7 Compensation for Assistance

This procedure contains no compensation provision for any party, but compensation is not precluded.

14.8 Responsibilities

14.8.1 Control Areas

It shall be the responsibility of each Control Area to follow policies and procedures contained herein; reporting daily information, identifying potential and actual transmission overloads and supplying assistance to members when directed

14.8.2 Operating Reliability Working Group

The Operating Reliability Working Group shall receive periodic reports of any implementation of Transmission Loading Relief. The Operating Reliability Working Group shall make a report of this information to the Markets and Operations Policy Committee at each regular meeting.

14.8.3 Reliability Coordinator

It shall be the responsibility of the Reliability Coordinator to provide daily analysis and monitor and evaluate real-time flows and voltages against appropriate SOLs and IROLs. The Reliability Coordinator shall be responsible for providing timely 24-hour coordination and implementation during Transmission Loading Relief periods and provide periodic reports to the Operating Reliability Working Group.

15.0 OPEN